20140227-3052 FERC PDF (Unofficial) 02/27/2014

Changes at n.6 and Para 1644 made pursuant to ERRATA of 3/7/14.

UNITED STATES OF AMERICA 146 FERC ¶ 63,019
FEDERAL ENERGY REGULATORY COMMISSION

BP Pipelines (Alaska) Inc.	Docket No. IS09-348-004 (Superseded)*
BP Pipelines (Alaska) Inc.	Docket No. IS09-395-004
BP Pipelines (Alaska) Inc.	Docket No. IS10-204-002
BP Pipelines (Alaska) Inc.	Docket No. IS10-491-000
ConocoPhillips Transportation Alaska Inc.	Docket No. IS09-384-004
ConocoPhillips Transportation Alaska Inc.	Docket No. IS10-205-003
ConocoPhillips Transportation Alaska Inc.	Docket No. IS10-476-001
ExxonMobil Pipeline Company	Docket No. IS09-391-004
ExxonMobil Pipeline Company	Docket No. IS09-177-005
ExxonMobil Pipeline Company	Docket No. IS10-200-002
ExxonMobil Pipeline Company	Docket No. IS10-547-000
Unocal Pipeline Company	Docket No. IS09-176-004 (Terminated)*
Unocal Pipeline Company	Docket No. IS07-41-005*
Unocal Pipeline Company	Docket No. IS08-53-005*
Unocal Pipeline Company	Docket No. IS10-52-001
Unocal Pipeline Company	Docket No. OR10-3-001
Unocal Pipeline Company	Docket No. IS10-490-000
Unocal Pipeline Company	Docket No. IS11-3-000 (Terminated)*
Koch Alaska Pipeline Company, L.L.C.	Docket No. IS10-54-001
Koch Alaska Pipeline Company, L.L.C.	Docket No. IS10-496-000 (Phase I)
BP Pipelines (Alaska) Inc.	Docket No. IS09-348-006 (Superseded)*
BP Pipelines (Alaska) Inc.	Docket No. IS09-395-006
BP Pipelines (Alaska) Inc.	Docket No. IS10-204-004
BP Pipelines (Alaska) Inc.	Docket No. IS10-491-003
ConocoPhillips Transportation Alaska Inc.	Docket No. IS09-384-006
ConocoPhillips Transportation Alaska Inc.	Docket No. IS10-205-005
ConocoPhillips Transportation Alaska Inc.	Docket No. IS10-476-003
ExxonMobil Pipeline Company	Docket No. IS09-391-006

* *See BP Pipelines (Alaska), Inc., et al.*, 138 FERC ¶ 63,003 (2012); *BP Pipelines (Alaska), Inc., et al.*, 138 FERC ¶ 63,004 (2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

ExxonMobil Pipeline Company	Docket No. IS09-177-007
ExxonMobil Pipeline Company	Docket No. IS10-200-004
ExxonMobil Pipeline Company	Docket No. IS10-547-002
Unocal Pipeline Company	Docket No. IS09-176-006 (Terminated)*
Unocal Pipeline Company	Docket No. IS07-41-007*
Unocal Pipeline Company	Docket No. IS08-53-007*
Unocal Pipeline Company	Docket No. IS10-52-003
Unocal Pipeline Company	Docket No. OR10-3-004
Unocal Pipeline Company	Docket No. IS10-490-002
Unocal Pipeline Company	Docket No. IS11-3-002 (Terminated)*
Koch Alaska Pipeline Company, L.L.C.	Docket No. IS10-54-003
Koch Alaska Pipeline Company, L.L.C.	Docket No. IS10-496-003 (Phase II)

INITIAL DECISION

(Issued February 27, 2014)

APPEARANCES

Steven H. Brose, Esq.; *Steven Reed, Esq.*; *Rita Lovett, Esq.*; *Daniel J. Poynor, Esq.*; *Dean Thompson, Esq.*; and *Geoffrey G. Hengerer, Esq.*; on behalf of ConocoPhillips Transportation Alaska, Inc.

Eugene R. Elrod, Esq.; *Christopher M. Lyons, Esq.*; *Daniel J. Brink, Esq.*; *David J. Lewis, Esq.*; *Kelly J. McFadden, Esq.*; *Douglas J. Serdahely, Esq.*; and *Emily Watkins, Esq.*; on behalf of ExxonMobil Pipeline Co.

Jonathan D. Simon, Esq.; and *Richard Curtin, Esq.*; on behalf of Petro Star, Inc.

J. Patrick Nevins, Esq.; *Robert A. McMillin, Esq.*; *Robert B. Wolinsky, Esq.*; *Virginia Vance, Esq.*; *Amy Hoff, Esq.*; and *Ruth Porter, Esq.*; on behalf of Unocal Pipeline Co.

John E. Kennedy, Esq.;[1] *James D. Decker, Esq.*; *John Haines, Esq.*; *Dean H. Lefler, Esq.*; *Paula W. Hinton, Esq.*; *Kathleen Spangler, Esq.*; *Dick Veerman, Esq.*; *Michelle T. Boudreaux, Esq.*; on behalf of BP Pipelines (Alaska) Inc.

[1] On March 7, 2013, BP Pipelines (Alaska) Inc. submitted a letter to the Commission Secretary requesting removal of James D. Decker, Esq. and John E. Kennedy, Esq. from the service list in several of the above-captioned dockets. The letter

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Bradley S. Lui, Esq.; *Stephen M. Colangelo, Esq.*; *Klinton S. Miyao, Esq.*; *Robert H. Loeffler, Esq.*; *Phillip A. Reeves, Esq.*; *Michael C. Geraghty, Esq.*; *John C. Hutchins, Esq.*; *Bruce Barnard, Esq.*; *Tim A. O'Brien, Esq.*; and *Betre M. Gizaw, Esq.*; on behalf of the State of Alaska.

Edward D. Greenberg, Esq.; *David K. Monroe, Esq.*; *Amy Kornahrens, Esq.*; and *Tina M. Grovier, Esq.*; on behalf of Koch Alaska Pipeline Co.

Dennis H. Melvin, Esq.; *Kenneth M. Ende, Esq.*; *James W. Bixby, Esq.*; *Derek Anderson, Esq.*; *Marcia A. Lurensky, Esq.*; *Joshua M. Hurwitz, Esq.*; and *Philip Mone, Esq.*;[2] on behalf of Commission Trial Staff.

M. Denyse Zosa, Esq.; *David D'Alessandro, Esq.*; *Travis A. Pearson, Esq.*; *Barbara Nault, Esq.*; *Bankston Gronning, Esq.*; and *Dennis Lane, Esq.*; on behalf of Flint Hills Resources, LP.

Joseph S. Koury, Esq.; *Jeffrey G. DiSciullo, Esq.*; *Andrew T. Swers, Esq.*; *Robin O. Brena, Esq.*; *Sherri B. Manuel, Esq.*; *Frederick Hahn, Esq.*; *David W. Wensel, Esq.*; *Kelly M. Helmbrecht, Esq.*; *Anthony S. Guerriero, Esq.*; and *Barron W. Dowling, Esq.*; on behalf of Anadarko Petroleum Corporation and Tesoro Alaska Company.

Thomas Gingras, Esq.; on behalf of Udelhoven Oil Field System Services, Inc.
Bradford Keithley, Esq. and *Glen S. Benson, Esq.*; on behalf of BP Exploration (Alaska) Inc.

Carmen A. Cintron, Presiding Administrative Law Judge

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further requested to add Martin M. Weinstein, Esq. and Elizabeth B. Kohlhausen, Esq. to the service list in several of the above-captioned dockets and some dockets held in abeyance, but not consolidated with these proceedings. Subsequently, on August 14, 2013, BP Pipelines (Alaska) Inc. submitted a letter to the Commission Secretary requesting removal of all individuals from the law firm Vinson & Elkins LLP from the service list, replacing them with Dean H. Lefler, Esq. and Elizabeth B. Kohlhausen, Esq. under the law firm Caldwell Boudreaux Lefler PLLC. Notices of appearance have not been filed by substituted counsels.

[2] On March 22, 2013, Commission Trial Staff filed a notice of substitution of counsel which removed James W. Bixby from the service list in these proceedings and substituted James W. Bixby with Philip Mone, Esq. The notice further advised of the appearance of Philip Mone, Esq.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

TABLE OF CONTENTS

PARAGRAPH

I. INTRODUCTION……..…..1

II. BACKGROUND……..…..6

III. PROCEDURAL HISTORY…….....28

IV. ISSUES……92

a. ISSUE 1: PRUDENCE……...92
i. Burden of Proof……...92
ii. Prudence……141
1. Synopsis of the Parties' Contentions……141
2. From 1997-2000…….....147
3. What happened in 2001…….283
4. What happened in 2002…….....354
5. What happened in 2003…….507
6. What happened in 2004…….770
7. What happened in 2005…….920
8. What happened in 2006……...1135
9. What happened in 2007……...1183
10. What happened in 2008……...1251
11. What happened in 2009……...1271
12. What happened in 2010……...1291
13. New State of Affairs……1305
iii. Disallowance……...1378
iv. Disallowance under Used and Useful and Other Ratemaking Principles…….1465
1. Used and useful……1465
2. Other ratemaking principles……1589

b. ISSUE 2: COST OF SERVICE…….1607
i. The 2009 and 2010 cost of service adjustments……1607
ii. The 2006 supplemental ad valorem tax……..1619
iii. Litigation expense……...1655
iv. Anadarko's proposed adjustments to rates…….1660
v. Other uncontested issues…….1661

V. CONCLUSIONS……..1666

VI. ORDER……1677

20140227-3052 FERC PDF (Unofficial) 02/27/2014

I. INTRODUCTION

1. The issue in this case is whether the Trans Alaska Pipeline System (TAPS) Carriers[3] 2009 and 2010 filed rates are just and reasonable. This inquiry involves determining whether the Carriers prudently incurred the costs of the Strategic Reconfiguration (SR) project. If SR costs were prudently incurred they can be included in in the 2009 and 2010 rates. Alternative theories of disallowance of the SR costs are also at issue. Additionally, cost of service items in the 2009 and 2010 filed rates are also challenged.

2. SR,[4] described in further detail below, essentially replaced gas fired turbine pumps with electric pumps at four pump stations on TAPS and upgraded control systems. The project was conceived in November 2001 and was scheduled to finish in 2005, but it is still not complete. The cost of the project is now at $750 million, which is triple the original estimate, and this figure is expected to increase as the project continues. In contrast to the SR project, the 800 miles of original pipeline took only three years to construct at a cost of $8 billion.

3. There is no question that the Commission has recognized that managers of a utility have broad discretion in conducting their business dealings. The State of Alaska (State), Anadarko Petroleum Corporation and Tesoro Alaska Company (Anadarko) raised serious doubts as to whether SR project expenses were prudently incurred. As a result, they shifted the burden to the Carriers to prove that the costs were prudent. The Carriers, who have the ultimate burden of proof failed to meet their burden and failed to prove that the costs were prudent. The evidence in this case proves the Carriers sanctioned the project with insufficient engineering. Further, they started construction with insufficient engineering, fast tracked the schedule, hired inexperienced contractors and failed to properly manage them and failed to implement an effective management of change process, among others. Therefore, the SR costs in this case are not costs which reasonable utility managers would have made in good faith, under the same circumstances and at the relevant point in time, as required by the Commission's prudence standard. Discussed below are the circumstances surrounding this project and the facts that the Carriers knew or should have known when making the decision to sanction and execute the project.

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[3] At the time this case started, the TAPS Carriers consisted of BP Pipelines (Alaska) Inc. (BP), ConocoPhillips Transportation Alaska, Inc. (Conoco), ExxonMobil Pipeline Company (Exxon), Koch Alaska Pipeline Company, LLC (Koch), and Unocal Pipeline Company (Unocal) (collectively, Carriers). These entities are sometimes referred to as Owners.

[4] SR is sometimes referred to as electrification, although electrification of the pumps was just one of its undertakings.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Changes pursuant to ERRATA of 3/7/14.

4. This decision finds that the SR expenses at issue (which at the time of this decision is approximately $750 million) were imprudently incurred and cannot be flowed through rates. A number of proposals were advanced as remedies for the imprudently incurred expenses. Of these, Anadarko's Remedy 3, excluding from rates all SR capital costs(excluding O&M) included in Authorization for Expenditure (AFE) S020 Supplement 2 and all SR AFEs thereafter is found to be equitable. Therefore, Supplement 2 costs and forward will not be included in the Carriers' rates. The Carriers may flow through rates the original costs in AFE S020 and Supplement 1, which is $229.2 million to be amortized over the remaining life of the pipeline. For the filed 2009 and 2010 rates, the rate base exclusion is $225.2 million. Under this remedy, future costs of PS 1 would not flow through rates since the original AFE S020 included PS1, thus avoiding any additional prudence litigation for SR. The costs for SR Supplement 2 and forward are deemed imprudent under the Commission's standards.

5. The parties resolved some of the cost of service issues in a settlement. As to the unresolved issues, this decision finds that it is appropriate to use actual cost data for the entire periods in this case, that the oil spill expense is appropriately excluded as a nonrecurring event, and that the supplemental ad valorem tax paid in 2010 for the 2006 tax year cannot be flowed through the 2010 rates.

II. BACKGROUND

6. TAPS consists of a 48-inch diameter oil pipeline and its related facilities. The pipeline is about 800 miles long and transports commingled crude oil produced from different fields on the Alaska North Slope (ANS) from Prudhoe Bay to the Port of Valdez. The pipeline was completed in 1977[5] at a cost of about $8 billion.[6]

7. At the time this case started, TAPS was owned by BP (46.93%), Conoco (28.29%), Exxon (20.34%), Koch (3.08%), and Unocal (1.36%). [7] These Carriers each

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[5] Construction started in 1974. Ex. SOA-427 at 8.

[6] Since it commenced operations in 1977, TAPS has transported over 15 billion barrels of oil. *BP Pipelines (Alaska) Inc., et al. v. State of Alaska Department of Revenue, et al.*, Case No. 3AN-063-08446 CI (Consolidated) (Alaska Super. Ct. Dec. 30, 2011) at P 63, *aff'd*, *BP Pipelines (Alaska) Inc. v. State, Dep't of Revenue*, Nos. S -14095, S -14116, S -14125, 2014 WL 685986, at 17 (Alaska, Feb. 19, 2014).

[7] Ex. SOA-427 at 5. Koch and Unocal provided notice to the Commission of their withdrawal from TAPS effective August 1, 2012 and transfer of their TAPS interests to the remaining owners. These parties also cancelled their Commission tariffs effective August 1, 2012. The Regulatory Commission of Alaska (RCA) approved Koch's transfer of its TAPS ownership interest. *In re the Joint Application Filed by Koch Alaska Pipeline Company, LLC*, 2012 WL 6628059 (Regulatory Commission of Alaska)

20140227-3052 FERC PDF (Unofficial) 02/27/2014

possess an undivided joint interest and entitlement to its percentage ownership share of the pipeline's capacity. This means that each Carrier operates its interest as though it were a separate pipeline; i.e., each Carrier posts its own tariffs and deals directly with its shippers.

8. The Carriers created a jointly-owned company, Alyeska Pipeline Service Company (Alyeska), as their agent and operator. Among other things, Alyeska is responsible for all of the TAPS maintenance, operations, legal, accounting, and personnel activities. Alyeska does not directly deal with shippers or collect tariff revenue, and receives all of its funding through cash calls from the Carriers.[8]

9. In 1985, the Carriers entered into a settlement agreement (TAPS Settlement) establishing the TAPS Settlement Methodology (TSM), used to calculate the annual maximum interstate ceiling rates for TAPS beginning on January 1, 1986.[9] The Federal

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December 14, 2012. *See also* Offer of Settlement and Application for Approval of Voluntary Pooling Agreement and Request for Expedited Consideration at 8 (Sept. 25, 2012). This settlement was approved by the Commission. *BP Pipelines (Alaska), Inc., et al.*, 144 FERC ¶ 61,025, at P 1 n.2 (2013) (Order on Contested Settlement).

As of the date of this order, it appears that Unocal's transfer of its ownership shares is not complete. The RCA issued an Order Extending Deadline for Filing of Application for Transfer of Operating Authority directing Unocal to file by April 25, 2013, an application to transfer its operating authority in TAPS or to file an explanation of the reasons why the transfer application had not been filed. *In the Matter of Request by Unocal Pipeline Company*, Docket No. P-12-013 (Regulatory Commission of Alaska) (February 4, 2013). On April 25, 2013, Unocal filed a compliance filing asserting that it was not in a position to file an application to transfer its operating authority. Unocal argued that it was in a dispute with the other Carriers concerning several transfer-related matters and that, by July 25, 2013, it would file its application or an explanation as to why the application could not be made. In addition, Unocal filed a petition for a declaratory order in Harris County, Texas district court to determine the rights and duties of the TAPS owners when an owner chooses to discontinue operations, on February 1, 2013. *Unocal Pipeline Company v. BP Pipelines (Alaska), Inc.*, Case No. 201306244-7, District Court Harris County, TX. 165 Jurisdictional District. Order on Contested Settlement, *supra.*

[8] Ex. SOA-427 at 42. A recurring theme throughout the Carriers briefs is the implied blame of either Alyeska or the SR project team. However, this decision treats Alyeska and the SR team as what they are, agents of the Carriers.

[9] The TAPS Settlement provided it would run until the end of 2011, and permitted early termination by 2008 if a party requested renegotiation of its terms and a new

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Energy Regulatory Commission (FERC or the Commission) approved the TAPS Settlement.[10]

10. In accordance with the ownership agreement at the time, two-thirds ownership majority and three owners (minimum), was required to authorize the project at issue in this proceeding.[11] This meant that this project required the approval of BP and one of the other major owners.

11. TAPS was designed for 12 pump stations, but only 8 operated at startup (PS Nos. 1, 3, 4, 6, 8, 9, 10 and 12). Pump station 2 was commissioned in 1979 and PS 7 in 1980. Pump station (PS) 11 was never built and PS 5 was built as a relief station. The original design was for 1.5 million barrels of oil per day (excluding use of a drag reducing agent which would allow throughput increase above the design maximum).[12] Throughput has been declining since its peak of 2 million barrels per day in 1988,[13] resulting in a number of pump stations being decommissioned.[14] Currently, there are only four pump stations 1, 3, 4 and 9.

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agreement was not reached. The State of Alaska (SOA) invoked this early termination provision, and the TAPS Settlement expired on December 31, 2008.

[10] *Trans Alaska Pipeline Sys.*, 33 FERC ¶ 61,064, at 61,140, *reh'g denied*, 33 FERC ¶ 61,392 (1985); *Trans Alaska Pipeline Sys.*, 35 FERC ¶ 61,425 (1986), *aff'd sub nom. Arctic Slope Reg'l Corp. v. FERC*, 832 F.2d 158 (D.C. Cir. 1987), *cert. denied* 488 U.S. 868 (1988).

[11] *See* Ex. SOA-226 at 1.

[12] Ex. SOA-11 at 6.

[13] Ex. ATC-19 at 8:3-7.

[14] PSs 8 and 10 were ramped down in 1996; PSs 2 and 6 in 1997. PS 12 was placed in ramp-down status on April 1, 2005. Ex. SOA-427 at 28.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

12. The pipeline was originally designed and constructed for remote operation.[15] The original turbine driven pumps were fueled by either natural gas or liquid fuel. Most of the pump stations had three pumps, each powered by a Rolls Royce Avon gas generator turbine and a Cooper Bessemer reaction turbine. Ex. ATC-19 at 13-14. These were the mainline units (MLUs). Each station had smaller Solar and Garrett turbines to generate electricity for pump station lightning, utilities and other uses. At a typical pump station, there were from two to seven turbines for power generation. *Id.* at 14. The Operations Control Center (OCC) was originally located at Valdez, the operators at Valdez would operate the pipeline. OCC controllers could start and stop the pumps at individual stations, determine pressure and relief set points, decide on drag reducing agent (DRA) injection rates, and determine when to fill and drain pump station relief tanks. In addition, they monitored the status of the mainline valves and tracked work crews along the pipeline itself.[16] Some functions such as power generation, gas compression, and facility heating could be controlled only by a local operator at the individual pump stations. Ex. ATC-19 at 16; Ex. ATC-891 at 8-9; Tr. 7390-92.

13. Personnel working at PS 3 and 4 were housed at Permanent Living Quarters (PLQ) prior to SR. These were self-sufficient with sleeping, recreation, dinning, power generation, water and sewage treatment facilities.[17] In addition, the pump stations could use Mobile Contingency Camp Facilities to house personnel if the need arose.[18] Personnel working at PS1 are housed at off-site facilities on the North Slope and will continue to be housed off-site after electrification. Personnel working at PS 9 both before and after electrification live in housing provided in the nearby town of Delta.

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[15] Exs. ATC-901 (originally the pump stations were designed to operate unmanned); Ex. SOA-572 at 13, n. 22 ("[p]ump stations were to be unmanned in conception; however, the startup phase presented challenges and shortly after start up Pump Station 8 had a massive explosion. As a result, people were deployed in the field to ensure reliability and they have been there ever since. The pipeline spill response organization has an ironic history as Alyeska had operations and maintenance people stationed in the pump stations for reliability and then after the Exxon Valdez spill personnel at the pump stations became the pipeline spill responders. This was a major challenge associated with the electrification project as minimum manning in the field is now dictated by spill response."); Ex. SOA-11 at 6 (on site personnel to monitor pipeline and pump station operations).

[16] Ex. ATC-250 at 5.

[17] *Id*. at 4, *see also* Tr. 6703:14-15 (Howitt) (describing PLQ); Ex. SOA-679 (building labeled 4).

[18] Ex. SOA-679 at 4 (building labeled 10); Tr. 6711-12 (Howitt).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

14. Pump station staffing is driven by operations, maintenance and emergency preparedness and oil spill response. The pump stations before electrification (although remotely operated) were staffed by operations crew (typically four technicians sometimes five or six) split in day and night shifts. These workers manned local control rooms, monitoring equipment (routine) and data collection activities. They also administered the local work control process, and performed a variety of administrative and minor maintenance activities.[19] The pump stations historically required 24-hour staffing per day, with 40-50 and sometimes up to 130 people at most stations. Carriers IB 17.

15. Maintenance personnel (both before and after electrification) are day-shift personnel.[20] After electrification, their work is planned and scheduled from maintenance bases (before this was done from the pump stations). The maintenance bases at PS 4 and 9 operate from the same facilities used by maintenance personnel prior to electrification except that now they bear the designation maintenance bases rather than pump station facilities. They are primarily within the pump station security fences.[21] Emergency preparedness and oil spill response personnel are now in regional maintenance centers (rather than at the pump stations). Personnel providing services to PS 4 are now assigned to PS 3 (after electrification).[22]

16. SR upgrades and automates control systems of four pumps (1, 3, 4 and 9), but only 3, 4 and 9 are complete. The project also included replacing the MLUs which up until that time had been gas turbine drivers for electric motors. Pump station 1 has not been finished and the Carriers estimate completion by 2014. The MLUs were replaced with smaller pumps driven by 6,500-horsepower, variable-speed electric motors. Except for PS 9, electricity was to be generated on-site using new gas turbine generators. Ex. ATC-19 at 18-21. The existing control systems were also replaced. The local control rooms at the pump stations would no longer be needed and SR eliminated the need for the Solar and Garrett power generation turbines and some buildings were also eliminated. Exs. ATC-18 at 5; ATC-19 at 18-25.[23]

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[19] Ex. ATC-250 at 5. Each pump station also had security and support requirements. Carriers IB 18.

[20] Tr. 6839:2-11.

[21] Ex. SOA-679, 680, 681, 682, 683 and 684.

[22] Ex. ATC-250 at 7.

[23] Several SR-related projects were defined and funded under separate AFEs. AFE S026 upgrades facilities and control systems at PS 5 (Ex. SOA-73). PS 7 is covered by AFE S027 (Ex. SOA-76), and the ramp down stations are covered in AFE S028 (Ex. SOA-80). AFE S041 (Ex. SOA-103; SOA-105) funded upgrades to the fire and gas systems in legacy buildings at PS 1, 3, 4 and 9 retained under SR.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

17. Some SR-related projects were system-wide. For instance, the revision to the Oil Spill Contingency Plan (OSCP), under this the emergency response bases were regionalized. Aspects of this project were funded under AFEs S023 (Ex. SOA-69), SO25 (Ex. SOA-72), SO31 (Exs. SOA-84; SOA-85), and SO43 (Ex. SOA-109). Another was the replacement of the SCADA system. This system provided both the hardware and the software allowing the pump stations to send operational data to the OCC allowing the OCC to monitor and control certain pump station functions. This work focused on the host computer at the OCC and associated software under AFE F370 submitted to the Carriers on September 2002. Ex. ATC-152. Replacement of the SCADA Wide Area Network (WAN) at each pump station was done under AFE S034. Ex. SOA-88. The Safety Integrity Pressure Protection System (SIPPS) was another system-wide project funded under AFE S038. Ex. SOA-93; SOA-95; SOA-96. SIPPS added the capability to shut down the units, stations and system in the event of a failure or upset condition. Ex. SOA-95 at 4.

18. SR is completed at PS 3, 4 and 9. Oil first flowed through a new SR facility on February 9, 2007 at PS 9 (Ex. ATC-377); on December 11, 2007 at PS 3 (Ex. ATC-383); and on May 21, 2009 at PS 4 (Ex. ATC-387). The legacy facilities at these stations have been removed from service. Ex. SOA-747. It is contemplated that PS1 will be completed by 2014. The Carriers have spent under AFE S020 and individual-station AFEs through March 2011, including expenditures for PS 1, a total of $576 million (of which $514.5 million is capital). Ex. SOA-582.[24] Total expenditures for other SR related projects (including OSCP, fire and gas upgrades, SCADA and SIPPS) were $132.1 million (of which $117.8 million is capital). *Id.*

A. 2005 and 2006 TAPS Rates

19. Pursuant to the TAPS Settlement, the Carriers file their individual interstate rates with FERC annually. The State and Anadarko filed protests and complaints alleging the Carriers' interstate rates for 2005 and 2006 calculated pursuant to the TSM were unjust and unreasonable. FERC accepted and suspended the 2005 and 2006 rates, subject to refund, consolidated the proceedings and set them for hearing.[25]

20. On May 17, 2007, FERC Administrative Law Judge Carmen A. Cintron issued an initial decision finding that the TSM no longer resulted in just and reasonable interstate

[24] Ex. SOA-582 is a regularly prepared Alyeska SR spend report for SR AFEs and SR-related AFEs.

[25] *BP Pipelines (Alaska) Inc.*, 113 FERC ¶ 61,332, at PP 2, 3 (2005).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

rates and rejected the Carriers' 2005 and 2006 filed rates.[26] In place of the TSM,[27] Judge Cintron held that the Carriers must calculate the rates for 2005 and 2006 in accordance with the ratemaking methodology in Opinion No. 154-B.[28] On June 20, 2008, FERC issued Opinion No. 502 affirming Judge Cintron on all issues except the return on equity issue.[29]

21. Prior to Opinion No. 502, each of the Carriers charged individual rates for interstate transportation service on TAPS, and these rates varied significantly between them.[30] Judge Cintron found that these variations between the individual rates were not caused by differences in cost of service expenses because each of the Carriers have almost the same cost of service.[31] It was determined that instead of each Carrier charging individual rates for transportation service, the Carriers should charge a uniform rate.[32]

22. The Carriers sought rehearing of Opinion No. 502, and BPPA individually requested rehearing on the pooling issue (which is briefly discussed below). By an order issued on November 20, 2008, FERC denied the Carriers' request for rehearing, affirmed that there must be a uniform rate on TAPS, and clarified that a pooling mechanism is necessary to ensure that certain Carriers do not over- or under-recover their costs under a uniform rate.[33]

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[26] *BP Pipelines (Alaska) Inc.*, 119 FERC ¶ 63,007, at PP 1, 70 (2007) (2007 Initial Decision).

[27] Prior to 2005, the Regulatory Commission of Alaska (RCA) determined that the TSM no longer resulted in just and reasonable intrastate rates and ordered the Carriers to follow a different ratemaking methodology, which substantially lowered the intrastate rates.

[28] *BP Pipelines (Alaska) Inc.*, 119 FERC ¶ 63,007 at P 47; *Williams Pipe Line Co.*, 31 FERC ¶ 61,377 (1985) which set forth generic principles for determining just and reasonable rates on oil pipelines and adopting a cost-based methodology for establishing those rates.

[29] *BP Pipelines (Alaska) Inc.*, 123 FERC ¶ 61,287 (2008) (Opinion No. 502).

[30] *BP Pipelines (Alaska) Inc.*, 127 FERC ¶ 61,316 (2009) at P 8.

[31] 2007 Initial Decision at P 251.

[32] *Id.* PP 252-256.

[33] *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 61,215, at PP 33, 55-57 (2008) (November 20, 2008 Order).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

23. FERC also accepted the Carriers' compliance filings for the 2005 and 2006 rates (calculated using test period data), which were below the 2004 rate refund level.[34] Accordingly, FERC ordered the Carriers to issue refunds limited to the difference between the 2005 and 2006 filed rates and the refund level.[35]

B. 2007 and 2008 TAPS Rates

24. Prior to Opinion No. 502, each of the Carriers submitted their individual annual interstate rate filings for 2007 and 2008 pursuant to the TSM. Several parties protested these rates, raising issues similar to those raised in the TAPS 2005 and 2006 rate proceeding. FERC accepted and suspended the Carriers' 2007 and 2008 rate filings, but held the proceedings in abeyance subject to the outcome of the 2005 and 2006 rate proceeding.[36]

25. On December 29, 2008, after Opinion No. 502 was issued, FERC summarily disposed of the Carriers' 2007 and 2008 interstate rate filings. Since the Carriers had calculated these filings pursuant to the TSM, FERC directed the Carriers to make a compliance filing recalculating the rates in accordance with the methodology set forth in Opinion No. 502.[37]

26. On January 28, 2009, the Carriers submitted a compliance filing establishing uniform rates for 2007 and 2008 in accordance with Opinion No. 502. A number of parties filed protests and comments on the compliance filing. On April 16, 2009, FERC issued an order accepting the 2007 rate.[38] FERC stated that because the 2007 uniform rate fell below the applicable refund level (i.e., the 2004 TAPS rates), no further proceedings regarding the 2007 rates were necessary, and the refunds were limited to the difference between the 2007 filed rate and the 2004 rate.[39] However, the proposed 2008 uniform rate was higher than the refund level. As a result, FERC accepted, on an interim basis, the tariffs containing the 2008 compliance filing rate, subject to refund, ordered

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[34] *Id.* P 115.

[35] *Id.* at ordering para. (D).

[36] *See BP Pipelines (Alaska) Inc.*, 117 FERC ¶ 61,352, at PP 1-3 (2006); *Unocal Pipeline Co.*, 121 FERC ¶ 61,300, at PP 1-11, 19 (2007). The FERC also accepted without suspension Conoco's FERC Tariff No. 12, effective January 1, 2007. *Id.* at ordering para. (A).

[37] *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 61,367, at P 19 (2008).

[38] *BP Pipelines (Alaska) Inc.*, 127 FERC ¶ 61,047 (2009) (April 16, 2009 Order).

[39] *Id.* P 42.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

preliminary refunds for 2008 (representing the difference between the originally filed 2008 TSM rate and the 2008 compliance filing rate), and established hearing and settlement procedures.[40] While a final decision on the 2008 rate was pending, FERC ordered the Carriers to charge, as an interim rate, the 2008 compliance filing rate of $3.45 per barrel.[41]

27. The parties settled their 2008 rate dispute, and FERC approved the settlement on April 1, 2010, terminating the dockets involving the 2008 rates.[42] The settlement agreement established rates of $3.33 per barrel.[43]

III. PROCEDURAL HISTORY

A. The Taps Rates in This Proceeding

i. The 2009 Rate Filings

28. On March 31, 2009, Exxon filed FERC Tariff No. 331 (Docket No. IS09-177-000) implementing a new interstate transportation rate for its share of TAPS capacity. ExxonMobil stated that it calculated its rate of $4.01 per barrel pursuant to the ratemaking methodology established in Opinion No. 502. The filing was protested by State and Anadarko Petroleum Corporation. On April 29, 2009, FERC accepted and suspended ExxonMobil's filing, effective May 1, 2009, subject to refund, and established hearing procedures.[44]

29. On March 31, 2009, Unocal filed FERC Tariff No. 298 (Docket No. IS09-176-000) establishing a volume incentive rate for transportation on its share of TAPS capacity. Unocal filed the volume incentive rate to compete with the other TAPS Carriers and encourage greater use of Unocal's share of the TAPS capacity. Unocal proposed a reduced rate of $3.25 per barrel to any interstate shippers who transport volumes averaging 5,000 barrels per day or more in a calendar month. Unocal stated it was not proposing to change its existing maximum rate (i.e., the interim rate of $3.45 established in the April 16, 2009 Order), which would remain applicable to shippers that do not satisfy the minimum volume threshold for the incentive rate. On April 28, 2009,

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[40] *Id.* PP 43, 47.

[41] *Id.* P 47 & n.37.

[42] *BP Pipelines (Alaska) Inc.*, 131 FERC ¶ 61,003 (2010).

[43] *Id.* P 2.

[44] *ExxonMobil Pipeline Co.*, 127 FERC ¶ 61,089 (2009).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

FERC accepted Unocal's filing, effective May 1, 2009, subject to refund[45] and conditioned its acceptance of Unocal's volume incentive rate on the outcome of the TAPS 2008 compliance rate proceeding in Docket No. IS07-75-000; if the final maximum rate determined there is less than Unocal's volume incentive rate, the refund condition will apply.[46]

30. On May 29, 2009, Unocal filed FERC Tariff No. 304, cancelling FERC Tariff No. 298 and implementing a base rate of $3.45 per barrel (the 2008 rate) and its volume incentive rate of $3.25 per barrel. The volume incentive rate brought forward the $3.25 rate of FERC Tariff No. 298. The State protested the filing, but FERC dismissed the protest as untimely. FERC Tariff No. 304 was accepted by order dated August 5, 2009 under Docket Nos. IS07-41-005 and IS08-53-005.[47] FERC granted rehearing and accepted the State's protest of Unocal's FERC Tariff No. 304. FERC also clarified that the tariff was accepted subject to refund and the outcome of final action in the TAPS 2008 compliance rate proceeding, the same conditions imposed on FERC Tariff No. 298.[48]

31. On June 11, 2009, BPPA filed FERC Tariff No. 39 (Docket No. IS09-395-000) to increase its interstate transportation rate to $4.10 per barrel effective August 1, 2009.[49] On June 3, 2009, ConocoPhillips filed FERC Tariff No. 17 (Docket No. IS09-384-000) to increase its interstate transportation rate to $4.10 per barrel effective July 4, 2009. On June 8, 2009, ExxonMobil filed FERC Tariff No. 351 (Docket No. IS09-391-000) to increase its interstate transportation rate to $4.10 per barrel, effective July 9, 2009.

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[45] *Unocal Pipeline Co.*, 127 FERC ¶ 61,088 (2009).

[46] *Id.* P 8.

[47] *Unocal Pipeline Co*., 128 FERC ¶ 61,138 (2009).

[48] *BP Pipelines (Alaska) Inc.*, 129 FERC ¶ 61,211, at P 28 (2009) (December 10, 2009 Order). The 2008 rate base issue was resolved by order dated April 1, 2010, *BP Pipelines (Alaska), Inc*., 131 FERC ¶ 61,003 (2010). As a result, by order issued January 25, 2012, Docket No. IS09-176-004 was terminated and Dockets IS07-41-005 and IS08-53-005 were added to deal solely with the FERC Tariff No. 304 volume incentive rate matter. *See BP Pipelines (Alaska) Inc*., 138 FERC ¶ 63,003 (2012).

[49] On May 29, 2009, BPPA filed FERC Tariff No. 38 in Docket No. IS09-348-000, proposing to increase its interstate transportation rate to $4.01 per barrel, effective July 1, 2009. This tariff was superseded by the filing of FERC Tariff No. 39 in Docket No. IS09-395-000. Docket No. IS09-348-004 was noted as superseded in an order issued January 25, 2012. It was not terminated for administrative reasons. *BP Pipelines (Alaska) Inc.*, 138 FERC ¶ 63,003 (2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

ConocoPhillips, BPPA and ExxonMobil stated that each calculated their rates in accordance with the ratemaking methodology prescribed by Opinion No. 502. Additionally, these same parties stated that the rates reflect the May 29, 2009 ruling by the Alaska State Assessment Review Board increasing the state property tax assessment on TAPS. The State and Anadarko protested these filings.

32. On June 30, 2009, FERC accepted and suspended the tariffs submitted by BPPA, ConocoPhillips, and ExxonMobil, subject to refund, to become effective on the dates requested, established hearing and settlement procedures, and consolidated these proceedings with those in Docket Nos. IS09-177-000 (ExxonMobil FERC Tariff No. 331) and IS09-176-000 (Unocal's volume incentive rate).[50] FERC further held the hearing and settlement procedures in abeyance pending the outcome of the proceeding in Docket No. IS07-75-000, *et al.*, discussed above.[51]

33. FERC found that BPPA, ConocoPhillips, and ExxonMobil made adequate initial showings that their filings meet the cost of service filing requirements under section 346.1 of FERC regulations[52] but also found that these filings raised issues of material fact that could not be resolved on the record. Therefore, FERC established hearing procedures to examine the varying data submitted by the Carriers and to determine, based on the ratemaking methodology in Opinion No. 502, one rate for transportation service on TAPS.[53]

34. FERC ordered that the hearing address the issues raised by the protestants, except the useful life of the line issue. Opinion No. 502 extended the useful life of the line from 2011 to 2034; FERC adhered to that finding,[54] but later granted the State and Anadarko's requests for rehearing on the TAPS end-life issue in a subsequent order.[55] In this decision FERC also clarified that the uniform rate constitutes a maximum rate for TAPS, but the Carriers may charge a lesser rate.[56]

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[50] June 30, 2009 Order at PP 1-4.

[51] *Id.*

[52] *Id.* P 26 (citing 18 C.F.R. § 346.1 (2008)).

[53] *Id.*

[54] April 16, 2009 Order at P 37; June 30, 2009 Order at P 27 (citing Opinion No. 502 at P 242).

[55] December 10, 2009 Order at P 1.

[56] *Id.* P 31.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

35. FERC further stated that in Opinion No. 502, it determined that the Carriers must charge a uniform rate for transportation service on TAPS. It explained that it is just and reasonable for the Carriers to charge one rate because they all provide identical interstate transportation service to shippers, regardless of whose capacity is used, and they all have basically the same cost of service.[57]

36. FERC also stated that while Opinion No. 502 clearly established that a uniform rate should apply for transportation service on TAPS, and each Carrier stated in its filing that it calculated its rate in accordance with Opinion No. 502, several Carriers have individually filed their own rates that vary and cover different periods of time.[58]

37. FERC also held that the hearing decision should establish a pooling mechanism for establishing rates on TAPS. In the November 20, 2008 Order, FERC explained that ordering pooling was necessary and incident to FERC establishing a just and reasonable rate.[59] In the Pooling Rehearing Order, FERC clarified that the TAPS pooling mechanism should reallocate the TAPS Carriers' costs based on throughput, so that the allocation of costs matches the allocation of revenues on TAPS. FERC also clarified that the Carriers must include the pooling mechanism in their tariff.[60] In accordance with these orders, FERC held that the hearing on the consolidated proceedings at issue here should establish both a uniform rate and a pooling mechanism for transportation service on TAPS.[61]

38. FERC held that based upon its review, the tariff filings by BPPA, ConocoPhillips, and ExxonMobil the proposed rates had not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory, or otherwise unlawful.[62] The FERC found that BPPA, ConocoPhillips, and ExxonMobil "seek to implement different rates for different periods of time, which is inconsistent with FERC's ruling in Opinion No. 502 that there should be one rate for transportation service on TAPS."[63] FERC further

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[57] *BP Pipelines (Alaska) Inc*., 127 FERC ¶ 61,316 (2009), (June 30, 2009 Order) at P 27 (citing Opinion No. 502 at P 242).

[58] *Id.* P 28.

[59] November 20, 2008 Order at PP 64, 67.

[60] *BP Pipelines (Alaska) Inc*., 127 FERC ¶ 61, 317 (2009) (Pooling Rehearing Order) at P 41 & n.45.

[61] June 30, 2009 Order at P 29.

[62] *Id.* P 32.

[63] *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

held that because it accepted and suspended each of the Carriers' individual rate filings, subject to refund, each Carrier could continue to charge the rate it filed until the just and reasonable uniform rate for TAPS is determined through settlement or hearing procedures.[64]

39. As previously mentioned, FERC held the hearing and settlement procedures in this consolidated proceeding in abeyance pending the outcome of the 2008 TAPS compliance filing rate proceeding in Docket No. IS07-75-000, *et al.* On October 21, 2009, the parties filed a motion requesting FERC to lift the abeyance and transfer the case to the Chief Judge to initiate settlement judge procedures. On October 27, 2009, FERC issued an order granting the motion to lift abeyance, and since the parties had reached an agreement on the 2008 rates, transferred the case to the Chief Judge to initiate settlement judge procedures.[65]

40. Settlement procedures regarding the 2009 rate filings were unsuccessful; the Chief Judge terminated settlement judge procedures and appointed Presiding Judge Michael J. Cianci.[66]

41. On January 13, 2010, the Chief Judge bifurcated the hearing into two proceedings: one for the Non-Strategic Reconfiguration issues (Non-SR proceedings) and another for the Strategic Reconfiguration issues (SR proceedings).[67] Judge Edward M. Silverstein was initially appointed to hear the SR issues phase by the Chief Judge on January 25, 2010. In the order, the Chief Judge stated that this bifurcation would enable the Non-SR proceedings to expeditiously proceed while allowing more time for the more complex SR phase. The Chief Judge ordered Judge Michael J. Cianci to preside over the Non-SR issues case, while the hearing in the SR issues proceeding would be conducted in Docket Nos. IS09-348-004, IS09-395-004, IS09-384-004, IS09-391-004, IS09-177-005, IS09-176-004.[68]

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[64] *Id.* P 33.

[65] *BP Pipelines (Alaska) Inc.*, 129 FERC ¶ 61,072, at P 6 (2009).

[66] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-000, *et al*., Order of Chief Judge Terminating Settlement Judge Procedures, Making Substitute Designation of Presiding Judge, and Establishing Track III Procedural Timelines, Docket No. IS09-348-000, *et al.* (Dec. 22, 2009).

[67] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-000, *et al*., Order of Chief Judge Severing Strategic Reconfiguration Issues and Scheduling Prehearing Conferences (Jan. 13, 2010).

[68] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, Order of Chief Judge Confirming Procedural Schedule, Approving Out of Town Hearing, and

20140227-3052 FERC PDF (Unofficial) 02/27/2014

ii. 2010 Rate Filings

42. On November 25, 2009, Unocal filed FERC Tariff No. 306 (Docket No. IS10-52-000) and Koch filed FERC Tariff No. 14 (Docket No. IS10-54-000) to increase the interstate rate on their respective portions of TAPS capacity from $3.45 per barrel to $4.08 per barrel, effective January 1, 2010. The FERC accepted these filings and consolidated them with the non-SR hearing docket IS09-348-000.[69]

43. On April 12 and 13, 2010, ExxonMobil, BPPA and ConocoPhillips filed Settlement Implementation Tariffs to comply with paragraph 3 of the TAPS 2008 Settlement Agreement, pursuant to which they reduced the rates filed in 2009. ExxonMobil filed FERC Tariff No. 361 (Docket No. IS10-200-000), BPPA filed FERC Tariff No. 40 (Docket No. IS10-204-000), and ConocoPhillips filed FERC Tariff No. 17, Supplement 1 (Docket No. IS10-205-000).[70] On April 23, 2010, ConocoPhillips filed FERC Tariff No. 17, Supplement 2 (Docket No. IS10-205-001) to correct certain references on the title page of the tariff, but not the rate. All of these tariff filings reduced the interstate rate on their respective portions of TAPS capacity from $4.10 per barrel to $4.08 per barrel. On May 12, 2010, the FERC consolidated Docket Nos. IS10-200-000 (ExxonMobil), IS10-204-000 (BPPA), and IS10-205-000 (ConocoPhillips) and IS10-205-001 (ConocoPhillips) with the two-phase proceedings in Docket No. IS09-348-000, *et al*. (investigating non-SR issues before Judge Cianci) and Docket No. IS09-348-004, *et al*. (investigating SR issues before Judge Silverstein).[71]

44. On July 1, 2010, ConocoPhillips filed FERC Tariff No. 18 (Docket No. IS10-476-000) to increase the interstate rate on its portion of TAPS capacity from $4.08 per barrel to $4.36 per barrel effective August 1, 2010. On July 29, 2010, the FERC accepted the

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Designating Presiding Administrative Law Judge (Jan. 25, 2010). In this order, the parties agreed to a procedural schedule for the SR proceeding. The procedural schedule agreed to by the parties was as follows: January 21, 2011, initial testimony for parties with burden; February 18, 2011, testimony for intervenors supporting party with burden; June 17, 2011, Answer Testimony for all Intervenors and Parties; July 15, 2011, Testimony by FERC Trial Staff; August 19, 2011, Reply Testimony for all Participants.

[69] *Unocal Pipeline Co., et al.*, 129 FERC ¶ 61,275 (2009).

[70] On May 29, 2009, ConocoPhillips filed FERC Tariff No. 16 to be effective July 1, 2009 (Docket No. IS09-357-000) implementing a rate of $3.99. The tariff was withdrawn before it became effective and replaced with FERC Tariff No. 17.

[71] *ExxonMobil Pipeline Co., et al.*, 131 FERC ¶ 61,133 (2010) (May 12, 2010 Order).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

tariff and consolidated the docket with the SR proceeding and held the non-SR issues in abeyance pending resolution of the Non-SR proceeding (Docket No. IS09-348-000, *et al.*).[72]

45. On July 16, 2010, Unocal filed FERC Tariff Nos. 309, 310, and 311 (Docket No. IS10-490-000) proposing minor non-rate related changes in order to comply with the FERC's Order No. 714.[73] Unocal also filed FERC Tariff No. 312, which restated its existing rate with no change effective August 16, 2010. On August 13, 2010, the FERC accepted Unocal's tariffs and consolidated the docket with the SR proceeding and held the Non-SR issues in abeyance pending resolution of the Non-SR proceeding.[74]

46. On July 16, 2010, BPPA filed FERC Tariff No. 41 (Docket No. IS10-491-000) to increase the rate on its portion of the TAPS capacity from $4.08 per barrel to $4.36 per barrel effective August 16, 2010. On August 13, 2010, FERC accepted the filing and consolidated it with the SR proceeding and held the Non-SR issues in abeyance pending resolution of the Non-SR proceeding.[75]

47. On July 20, 2010, Koch filed FERC Tariff No. 15 (Docket No. IS10-496-000) to increase the interstate rate on its portion of TAPS capacity from $4.08 per barrel to $4.37 per barrel effective August 20, 2010. On August 18, 2010, FERC accepted the filing, consolidated it with the SR proceeding, and held the Non-SR issues in abeyance pending resolution of the Non-SR proceeding.[76]

48. On July 30, 2010, ExxonMobil filed FERC Tariff No. 380 (Docket No. IS10-547-000) to increase the interstate rate on its portion of TAPS capacity from $4.08 per barrel to $4.39 per barrel effective September 1, 2010. On August 31, 2010, FERC accepted the filing, consolidated it with the SR proceeding and held in abeyance the Non-SR issues pending resolution of the Non-SR proceeding.[77]

49. On October 1, 2010, Unocal filed FERC Tariff No. 318.1.0 (Docket No. IS11-3-000) to increase the interstate rate on its portion of TAPS from $4.08 per barrel to $4.38 per barrel effective November 1, 2010. On October 28, 2010, FERC accepted Unocal's

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[72] *See ConocoPhillips Transp. Alaska, Inc., et al.*, 132 FERC ¶ 61,084 (2010).

[73] *Electronic Tariff Filings*, 124 FERC ¶ 61,270 (2008) (Order No. 714).

[74] *Unocal Pipeline Co.*, 132 FERC ¶ 61,129, at P 8 (2010).

[75] *BP Pipelines (Alaska) Inc.*, 132 FERC ¶ 61,130 (2010).

[76] *Koch Alaska Pipeline Co., LLC*, 132 FERC ¶ 61,144 (2010).

[77] *ExxonMobil Pipeline Co.*, 132 FERC ¶ 61,193 (2010).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

tariff and consolidated the docket with the SR proceeding and held the Non-SR issues in abeyance pending resolution of the Non-SR proceeding.[78]

iii. 2011, 2012 and 2013 Rate Filings

50. On April 28, 2011, ConocoPhillips filed FERC Tariff No. 19.2.0 (Docket No. IS11-306-000) to increase the rate from $4.36 to $5.05 per barrel effective May 29, 2011. On May 11, 2011, Koch filed FERC Tariff No. 20.2.0 (Docket No. IS11-328-000) for a rate increase from $4.37 to $5.05 per barrel effective June 5, 2011. On May 26, 2011, FERC accepted the filings and consolidated them with the SR proceeding. The Non-SR issues were held in abeyance pending resolution of the Non-SR proceeding.[79]

51. However, upon acceptance of other tariffs, FERC reversed the decision to consolidate these dockets with the SR proceeding.[80] In this decision, FERC accepted BPPA's FERC Tariff No. 43.1.0 (Docket No. IS11-335-000) to increase its rate from $4.36 to $5.05, effective June 13, 2011. It also accepted ExxonMobil's FERC Tariff No. 402.1.0 (Docket No.IS11-336-000) filed on May 16, 2011, to increase its rate from $4.39 to $5.07, effective July 1, 2011. These filings were consolidated with IS11-306-000 and IS11-328-000 and held in abeyance pending the outcome of the Non-SR proceeding.[81]

52. On August 1, 2011, Unocal filed FERC Tariff No. 318.2.0 (Docket No. IS11-546-000) to cancel FERC Tariff No. 318.1.0 (Docket No. IS11-3-000). The new filing, which proposed to increase its rate from $4.38 to $4.98 per barrel effective September 1, 2011, was accepted and consolidated with Docket Nos. IS11-306-000, IS11-328-000, IS11-335-000, and IS11-336-000. All of these dockets were held in abeyance pending the outcomes of both the Non-SR and SR proceedings.[82] The fact that Unocal's new tariff superseded its previously filed FERC Tariff No. 318.1.0 rendered Docket No. IS11-3-000 moot. Consequently, Docket No. IS11-3-000 was terminated by order issued January 25, 2012.[83]

53. On May 31, 2012, ExxonMobil filed FERC Tariff No. 402.2.0, which proposed to increase its rate from $5.07 to $5.97 per barrel, to be effective July 1, 2012 (Docket No.

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[78] *Unocal Pipeline Co.*, 133 FERC ¶ 61,091 (2010).

[79] *ConocoPhillips Transp. Alaska, Inc.*, 135 FERC ¶ 61, 184, at P 8 (2011).

[80] *See BP Pipelines (Alaska) Inc*., 135 FERC ¶ 61,221, at P 8 (2011).

[81] *Id.*

[82] *Unocal Pipeline Co*., 136 FERC ¶ 61,144, at PP 1, 17 (2011).

[83] *BP Pipelines (Alaska) Inc.*, 138 FERC ¶ 63,003 (2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

IS12-397-000). FERC accepted and suspended ExxonMobil's filing, effective July 1, 2012, subject to refund and further order of the FERC.[84] FERC's order also consolidated Docket No. IS12-397-000 with the 2011 dockets consolidated under IS11-306-000, *et al.*[85]

54. A FERC order was also issued regarding BPPA's FERC Tariff No. 43.2.0 (Docket No. IS12-458-000) filed on June 13, 2012. BPPA proposed in its 2012 tariff filing to increase the interstate rate from $5.05 per barrel to $5.97 per barrel to be effective July 13, 2012. Additionally, BPPA filed a petition for partial waiver of section 346.2(a)(1)(ii) of the FERC's regulations to allow rate changes (Docket No. OR12-20-000) using base and test period data consistent with the data reflected in ExxonMobil's 2012 filing. The FERC order accepted and suspended BPPA's tariff, subject to refund and consolidated IS12-458-000 and OR12-20-000 with the consolidated 2011 tariff filings.[86]

55. On July 5, 2012, ConocoPhillips filed FERC Tariff No. 19.3.0 (Docket No. IS12-498-000), effective August 5, 2012, to increase to the rate from $5.05 to $6.06 per barrel. The State and Anadarko filed protests to ConocoPhillips' rate filing. FERC accepted and suspended the referenced tariff record, subject to refund, and consolidated ConocoPhillips' rate filing with the consolidated proceedings in Docket No. IS11-306-000, *et al*. being held in abeyance pending the outcome of the consolidated cases in Docket No. IS09-348-000, *et al*.[87]

56. On November 29, 2012 BPPA filed Tariff 43.3.0, (Docket No. IS13-62-000) to decrease the interstate transportation rate from $5.97 per barrel to $5.77 per barrel, on its share of the capacity of TAPS to become effective January 1, 2013. The State and Anadarko filed protests to BPPA's rate filing. FERC accepted and suspended the tariff to become effective January 1, 2013, subject to refund, and consolidated the filing with the consolidated proceeding in Docket No. IS11-306-000 being held in abeyance pending the outcome of the consolidated cases in Docket No. IS09-348-000, *et al*.[88]

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[84] *ExxonMobil Pipeline Company*, 139 FERC ¶ 61,268 (2012).

[85] In the order, FERC explained that the parties treat Docket No. IS11-306-000 (ConocoPhillips' 2011 tariff filing) as the lead docket for the consolidated TAPS 2011 rating filings (*Id.* n.5), notwithstanding the fact that the order consolidating the 2011 rate filings listed Unocal's 2011 rate filing Docket No. IS11-546-000 first, which is customarily done with the lead docket. *Unocal Pipeline Company, et al.*, 136 FERC ¶ 61,144 (2011).

[86] *BP Pipelines (Alaska) Inc.*, 140 FERC ¶ 61,025 (2012).

[87] *ConocoPhillips Transp. Alaska, Inc*., 140 FERC ¶ 61,105 (2012).

[88] *BP Pipelines (Alaska) Inc.*, 141 FERC ¶ 61,252 (2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

57. Also on November 29, 2012, Exxon filed a FERC Tariff No. 402.3.0,3.0.0 (Docket No. IS13-55-000) to become effective January 1, 2013. Exxon proposes to increase the interstate rate for transportation of crude oil on its share of the capacity for TAPS from $5.97 to $6.24 per barrel. The State and Anadarko filed protests to the rate filing. The Commission accepted and suspended the filing to become effective January 1, 2013, subject to refund and consolidated the filing with the consolidated proceedings in Docket No. IS11-306-000 et al., which is being held in abeyance pending the outcome of the pending consolidated cases in Docket No. IS09-348-000.[89]

58. On December 18, 2012, BPPA filed a tariff No. 43.4.0,43.4.0, (Docket No. IS13-108-000) to become effective January 18, 2013. BPPA is proposing to cancel its tariff No. 43.3.0 and to increase its rate for interstate transportation of crude oil on TAPS from $5.77 to $6.24 per barrel. The Commission accepted and suspended the tariff to become effective January 18, 2013, subject to refund. The filing was consolidated with the already-consolidated proceedings in Docket No. IS11-306-000, *et al*. which are being held in abeyance pending the outcome of the consolidated cases in Docket No. IS09-348-000, *et al*.[90]

59. On January 2, 2013, Conoco filed FERC tariff 19.4.0,1.0.0, (Docket No. IS13-125-000) to become effective January 1, 2013. Conoco proposes to decrease its interstate rate for transportation of crude oil on TAPS from $6.06 to $5.92 per barrel. The State and Anadarko filed protest to the filing. The Commission accepted and suspended the tariff to become effective January 1, 2013, subject to refund. The filing was consolidated with the already-consolidated proceedings in Docket No. IS11-306-000, *et al*. which are being held in abeyance pending the outcome of the consolidated cases in Docket No. IS09-348-000, *et al*.[91]

60. On June 28, 2013, Conoco filed tariff 19.5.0,1.0.0 (Docket No. IS13-480-000) to become effective August 1, 2013 to increase its transportation rate on TAPS from $5.92 to $6.68 per barrel. Exxon also filed a tariff on the same date, FERC 402.4.0,4.0.0 (Docket No. IS13-496-000) to increase its tariff on TAPS from $6.24 to $6.68 per barrel. Anadarko and the State protested the filings. The Commission accepted and suspended the tariffs to become effective August 1, 2013 for Conoco and August 2, 2013 for Exxon, subject to refund. The filings were consolidated with the already-consolidated

[89] *ExxonMobil Pipeline Company*, 141 FERC ¶ 61, 261 (2012)

[90] *BP Pipeline (Alaska) Inc.*, 142 FERC ¶ 61,046 (2013).

[91] ConocoPhillips Transportation Alaska, Inc., 142 FERC ¶ 61,080 (2013).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

proceedings in Docket No. IS11-306-000, *et al*. which are being held in abeyance pending the outcome of the consolidated cases in Docket No. IS09-348-000, *et al.*[92]

61. On July 9, 2013, BPPA filed a tariff No. 43.0.0,43.5.0 to become effective August 9, 2013. BPPA proposes to increase its rate for transportation on TAPS from $6.24 to $6.68 per barrel. Anadarko and the State protested the filing. The Commission accepted and suspended the tariff to become effective August 9, 2013, subject to refund. The filing was consolidated with the already-consolidated proceedings in Docket No. IS11-306-000, *et al*. which are being held in abeyance pending the outcome of the consolidated cases in Docket No. IS09-348-000, *et al.*[93]

B. Orders of the Chief Judge on the Rate Filings

62. On May 26, 2010, the Chief Judge issued an order terminating the sub-dockets created for the Settlement Implementation Tariffs filed by ExxonMobil, BPPA, and ConocoPhillips (Dockets Nos. IS10-200-001, IS10-205-002 and IS10-204-001).[94] The following dockets were consolidated in the proceeding before Judge Cianci: IS09-348-000, IS09-395-000, IS09-384-000, IS09-391-000, IS09-177-000, IS09-176-000, IS10-52-000, OR10-3-000, IS10-54-000, IS10-200-000, IS10-204-000, IS10-205-000, and IS10-205-001.[95] Further, the following dockets were consolidated in the proceeding before Judge Silverstein: IS09-348-004, IS09-395-004, IS09-384-004, IS09-391-004, IS09-177-005, IS09-176-004, IS10-52-001, OR10-3-001, and IS10-54-001. The Chief Judge noted that Judges Silverstein and Cianci had advised that there were no tariff issues present in the SR proceeding pending before Judge Silverstein, and that the tariff issues consolidated by the FERC into these proceedings by the May 12, 2010 Order would be heard in Docket No. IS09-348-000, *et al.* (Non-SR issues proceeding) pending before Judge Cianci.[96]

63. After the Chief Judge's May 26, 2010 order, the parties submitted a clarification letter to the Chief Judge dated July 12, 2010, requesting that the issues before Judge Cianci be limited to cost of capital, adoption of the pooling mechanism, and the

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[92] *Conoco Phillips Transportation Alaska, Inc. and ExxonMobil Pipeline Company*, 144 FERC ¶ 61,080 (2013).

[93] *BP Pipelines (Alaska) Inc.,* 144 FERC ¶ 61, 112 (2013).

[94] *BP Pipelines (Alaska) Inc., et al.,* Docket No. IS09-348-000, *et al.*, Order of Chief Judge on Newly Consolidated Tariffs at P 5 (May 26, 2010).

[95] May 12, 2010 Order at P 31.

[96] *BP Pipelines (Alaska) Inc., et al.,* Docket No. IS09-348-000, *et al.*, Order of Chief Judge on Newly Consolidated Tariffs at P 2 (May 26, 2010).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

implementation process for the uniform rate.[97] The Chief Judge accepted the parties' clarification.[98]

C. Orders Addressing SR Issues

64. FERC ordered joint proceedings between the RCA and the FERC on January 20, 2010.[99] Subsequently, the Chief Judge established procedures for a joint hearing by order dated October 25, 2010.[100] In this order, a concurrent hearing schedule at Anchorage, AK and Washington, DC was established. On October 27, 2010, the Chief Judge

[97] In the Non-SR hearing, the parties entered into a stipulation resolving the cost of capital issues related to the 2009 rates. They resolved the nominal and real rate of return on equity, inflation rate, cost of debt, and capital structure. Judge Cianci issued an initial decision resolving the pooling and uniform rate issues on March 10, 2011. *BP Pipelines (Alaska) Inc., et al.*, 134 FERC ¶ 63,020, at P 42 (2011). This decision is pending before the FERC on exceptions. However, on February 17, 2012, BPPA, ConocoPhillips, and ExxonMobil filed a motion for the FERC to direct the Chief Judge to appoint a settlement judge for settlement proceedings concerning the pooling mechanism issues already ruled on by Judge Cianci in his initial decision and before the FERC on exceptions. The FERC issued an order on April 23, 2012 directing the Chief Judge to appoint a settlement judge, and the parties chose Judge John P. Dring. *See BP Pipelines (Alaska), Inc., et al.*, 139 FERC ¶ 61,065 (2012). Chief Judge Wagner appointed Judge Dring as settlement judge over settlement of the pooling issues in Docket No. IS09-348-007 by order dated May 2, 2012. On September 25, 2012, BPPA, ExxonMobil, and ConocoPhillips filed an offer of settlement and application for approval of voluntary pooling agreement to resolve the pooling issues, [*see supra* note 4], which was contested. *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-007, *et al.*, Report of Contested Settlement (Jan. 8, 2013). On July 16, 2013, the Commission issued an Order on Contested Settlement approving the three agreements discussed therein without modification. *BP Pipelines (Alaska), Inc., et al.*, 144 FERC ¶ 61,025 (2013).

[98] Chief Judge Wagner emailed the parties in response to their letter on July 12, 2010, stating that the Chief Judge's May 26, 2010 order should not be construed to change or modify the previously agreed issues for the SR and non-SR phases. Additionally, the Chief Judge clarified that newly consolidated proceedings for the Non-SR proceedings included Docket Nos. IS10-200-000, IS10-204-000, IS10-205-000, and IS10-205-001. Subsequently, Chief Judge Wagner emailed the parties on July 13, 2010 assigning sub-docket Nos. IS10-200-002, IS10-204-002, and IS10-205-002 to the SR proceeding.

[99] BP Pipelines (Alaska), Inc., et al., 130 FERC ¶ 61,042 (2010).

[100] BP Pipelines (Alaska) Inc., et al., Docket No. IS09-348-004, et al., Order of the Chief Judge Establishing Procedures for Hearing (Oct. 25, 2010).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

designated Carmen A. Cintron as the Presiding Judge to replace Judge Silverstein for the SR proceedings.[101]

65. Following a prehearing conference in Anchorage, AK on August 25, 2011, the Chief Judge ordered that the proceeding be split into two phases: the first addressing SR prudence issues (Phase I) and the second addressing all outstanding rate issues (Phase II).[102] On December 12, 2011, the Chief Judge established the briefing and initial decision dates for the SR proceeding.[103]

66. Prior to the commencement of the hearing, discovery disputes arose with regard to the classification of certain exhibits. There was also a dispute regarding the terms of the protective order. Several orders were issued by the Presiding Judge and the FERC on these issues, and the disputes were resolved in a timely manner.[104]

67. The Phase I prudence portion of the hearing commenced on October 31, 2011, in Anchorage, AK, and continued there until November 16, 2011. The hearing resumed in Washington, DC on November 30, 2011 and continued until December 16, 2011. After a break for the winter holidays, the hearing resumed again in Washington, DC on January 9, 2012 and continued until January 17, 2012. The evidentiary record was closed for Phase I on January 17, 2012. Over 1,400 exhibits were admitted at the Phase I hearing.

68. Immediately following the conclusion of the Phase I hearing on January 17, 2012, a pre-hearing conference was held with Chief Judge Wagner, the Presiding Judges, RCA Commissioners, and all participants to establish dates for Phase II. During the Phase II pre-hearing conference, Chief Judge Wagner scheduled the Phase II hearing to commence on July 5, 2012. New subdockets were assigned to the Phase II hearing as follows: IS09-348-006, IS09-395-006, IS10-204-004, IS10-491-003, IS09-384-006, IS10-205-005, IS10-476-003, IS09-391-006, IS09-177-007, IS10-200-004, IS10-547-

[101] BP Pipelines (Alaska) Inc., et al., Docket No. IS09-348-004, et al., Designation of Presiding Administrative Law Judge (Oct. 27, 2010).

[102] BP Pipelines (Alaska) Inc., et al., 136 ¶ FERC 63,009 (2011).

[103] BP Pipelines (Alaska) Inc., et al., Docket No. IS09-348-004, et al., Order of Chief Judge Revising Procedural Schedule (Dec. 12, 2011).

[104] *See* BP Pipelines (Alaska) Inc., et al., Docket No. IS09-348-004, et al., Order on Interlocutory Appeal (June 27, 2011).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

002, IS09-176-006, IS07-41-007, IS08-53-007, IS10-52-003, OR10-3-004, IS10-490-002, IS11-3-002, IS10-54-003, and IS10-496-003.[105]

69. The main issues raised during the January 17, 2012 pre-hearing conference with Chief Judge Wagner were: the outstanding 2010 cost of capital issues not included in the settlement reached in Judge Cianci's dockets;[106] the life of the pipeline; whether there should be a concurrent hearing for Phase II; and whether Judge Sharon L. Gleason's December 30, 2011 Decision[107] (Ad Valorem Decision) should be given weight or merit, admitted as evidence, or accorded official notice in Phase II of this proceeding. The Carriers requested that if the Ad Valorem Decision was going to be admitted as evidence, it should be presented as additional evidence according to a procedural schedule, with the Carriers being permitted to respond to the Ad Valorem evidence submitted by the other parties.[108]

70. Judge Wagner ordered the parties to submit briefs on or before February 3, 2012 on the weight to be given the Ad Valorem Decision in the Phase II hearing. The Carriers, FERC Trial Staff (Staff), Flint Hills Resources Alaska, LLC, (Flint Hills), and Anadarko filed briefs regarding the Ad Valorem Decision on February 3, 2012. The briefs addressed whether dispositive motions regarding the life of the line were appropriate in light of the Ad Valorem Decision, the weight to be given, if any, to the Ad Valorem Decision, and whether all testimony and exhibits had been filed for Phase II. Chief Judge Wagner issued a ruling on February 6, 2012 in which he took official notice of the Ad Valorem Decision. However, Chief Judge Wagner gave the Presiding Judges the discretion as to the weight to give the Ad Valorem Decision and whether any additional testimony or exhibits needed to be filed. Additionally, Chief Judge Wagner designated

[105] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order of Chief Judge Confirming Procedural Schedule, Approving out of Town Hearing, and Designating Presiding Administrative Law Judge at P 1 (Jan. 25, 2010).

[106] Tr. 30-32:11-7 (Docket No. IS09-348-006, Vol. 1).

[107] This was a Decision Following Trial De Novo on the 2007, 2008, and 2009 Assessed Valuations of the Trans Alaska Pipeline System in the Superior Court for the State of Alaska, Third Judicial District at Anchorage, in Case No. 3AN-063-08446 CI. *BP Pipelines (Alaska) Inc., et al. v. State of Alaska Department of Revenue, et al.*, Case No. 3AN-063-08446 CI (Consolidated) (Alaska Super. Ct. Dec. 30, 2011).

[108] Tr. 34:18-24 (Docket No. IS09-348-006, Vol. 1).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the Presiding Judge for Phase II and set Phase II to commence on July 10, 2012 at 10:00 a.m. in Washington, DC.[109]

71. On February 10, 2012 the Carriers filed a motion to hold a concurrent hearing for Phase II. Anadarko, the State, and Staff also collectively filed a motion for a concurrent hearing in Phase II. Chief Judge Wagner emailed all parties on February 17, 2012, requesting that they file a pleading outlining all testimony and exhibits filed with FERC and RCA and outlining the witnesses testifying in each jurisdiction per issue. Chief Judge Wagner further requested that the parties outline any issues and/or evidence that are exclusive to either FERC or RCA. The TAPS Carriers, along with Flint Hills, responded to Chief Judge Wagner's February 17, 2012 email with a clarification pleading on February 22, 2012. Anadarko, the State, and Staff also filed responsive pleadings on February 22, 2012.

72. Chief Judge Wagner, on February 27, 2012, approved the parties' request for concurrent hearings, scheduled the time and location of the Phase II hearing, and allowed supplemental testimony for the life of line and Ad Valorem Decision issues.[110] In his February 27, 2012 order, Chief Judge Wagner also scheduled the Phase II hearing to commence on July 10, 2012 and continue through July 19, 2012 in Anchorage, AK. He ordered that the hearing would then recess and reconvene in Washington, DC on July 23, 2012 and continue in Washington, DC until its conclusion. The Washington, DC start date was later changed from July 23, 2012 to July 25, 2012 to allow everyone time to move the hearing to Washington, DC.[111] Chief Judge Wagner also permitted any party or participant wishing to file additional testimony addressing the evidence considered in the Ad Valorem Decision to do so by May 4, 2012. Any party wishing to file reply testimony and exhibits to opposing parties' filed Ad Valorem testimony, were permitted to do so by June 19, 2012.[112]

73. Post-hearing initial briefs for Phase I were filed on March 2, 2012, by Anadarko/Tesoro, the TAPS Carriers, the State, and Staff. Reply briefs were filed by Anadarko/Tesoro, the TAPS Carriers, the State and Staff on March 30, 2012. The initial

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[109] *BP Pipelines (Alaska) Inc.*, *et al.*, Docket No. IS09-348-006, *et al.*, Order of Chief Judge Ruling on Issues to be Considered in Phase II and Designating Presiding Administrative Law Judge (Feb. 6, 2012).

[110] *BP Pipelines (Alaska) Inc.*, *et al.*, Docket No. IS09-348-006, *et al.*, Order of Chief Judge Approving Concurrent Hearings, Scheduling Date and Place of Hearings, Providing for Supplemental Testimony (Feb. 27, 2012) (February 27, 2012 Order).

[111] *BP Pipelines (Alaska) Inc.*, *et al.*, Docket No. IS09-348-006, *et al.*, Order of Chief Judge Modifying Hearing Date in Washington, DC (Mar. 23, 2012).

[112] February 27, 2012 Order at P 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

decision for Phase I regarding prudence of the Strategic Reconfiguration was set to be due June 29, 2012.

74. On March 15, 2012, the Carriers filed a motion for clarification on Chief Judge Wagner's February 27, 2012 Order, specifically, to modify Paragraph 3 therein. The TAPS Carriers simultaneously filed a Motion to Exclude the Alaska Superior Court's Ad Valorem Taxation Ruling on March 15, 2012.

75. Anadarko and Staff filed replies on April 9, 2012 opposing the TAPS Carriers' Motion for Clarification. Staff advised that State joined in their reply. The same parties also filed replies on April 13, 2012 opposing the TAPS Carriers' Motion to Exclude the Ad Valorem Decision. The TAPS Carriers filed an Answer to Anadarko and Staff's replies on April 13, 2012 in which they essentially agreed with Anadarko and Staff's replies. In his order issued April 17, 2012, Chief Judge Wagner found the TAPS Carriers' Motion for Clarification to be moot by their filed answer. Chief Judge Wagner also reiterated his previous ruling that the admissibility of and extent to which the Ad Valorem Decision and evidence would be relied upon was at the discretion of the Presiding Judges.[113] An order was issued by the Presiding Judges on April 17, 2012 denying the TAPS Carriers' Motion to Exclude the Ad Valorem Decision.

76. On April 17, 2012, the Carriers requested permission to file a new depreciation study for Phase II. Chief Judge Wagner stated in his April 17, 2012 Order that he deferred to the Presiding Judges regarding the TAPS Carriers' Motion for a Depreciation Study, and that the parties should be prepared to argue the TAPS Carriers' Motion for a Depreciation Study during oral argument scheduled in Phase I (Docket No. IS09-348-004, *et al.*).

77. Burden of proof issues were initially raised in the Carriers' reply brief for the Phase I hearing. The TAPS Carriers asserted that the protestants changed their position on burden of proof and argued in their post hearing briefs that the TAPS Carriers bear the burden of proving that the expenditures related to SR were prudent. The record was reopened and an oral argument was held on April 19, 2012 on the burden of proof issue in Phase I and the Carriers' Motion for a Depreciation Study in Phase II.[114] Following the oral argument, it was decided that the TAPS Carriers would be given an opportunity

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[113] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-006, *et al.*, Order of Chief Judge on TAPS Carriers' Request for Clarification, Docket No. IS09-348-006, *et al.* (Apr. 17, 2012) (April 17, 2012 Order). Chief Judge Wagner previously ruled on these issues in his February 6, 2012 order.

[114] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order Re-Opening the Record, Requiring Briefs and Oral Argument (Apr. 5, 2012). The protestants, the TAPS Carriers, and Staff all filed briefs on the issue of burden of proof on April 12, 2012 prior to the oral argument.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

to file an additional round of testimony by June 4, 2012, to rebut the reply testimony of the protestants.[115] The Presiding Judges also ordered a supplemental Phase I hearing to be conducted after completion of the Phase II hearing in order to give the protestants and Staff ample time to review the TAPS Carriers' reply testimony, conduct discovery on TAPS Carriers' reply testimony and have an opportunity to cross examine the TAPS Carriers' rebuttal witnesses.[116] The TAPS Carriers withdrew their Motion for a Depreciation Study during the oral argument, and thus a ruling on that request was not necessary.[117]

78. In light of the fact that new evidence was going to be filed in both Phase I and Phase II of the proceeding, and that a supplemental hearing would be scheduled for Phase I, Chief Judge Wagner, on May 4, 2012, suspended the Phase I initial decision date of June 29, 2012, ordered one initial decision for both phases of this proceeding, and established dates for the supplemental Phase I hearing. The supplemental hearing was scheduled to commence on September 5, 2012 until September 14, 2012 in Anchorage, Alaska, at which time the hearing would recess and then reconvene in Washington, DC on September 19, 2012 until its conclusion.[118]

79. Anadarko, the Carriers, and Staff filed their Ad Valorem testimony in Phase II on May 4, 2012 and filed reply testimony in Phase II on June 19, 2012. The TAPS Carriers filed Motions to Strike portions or all of both Staff and Anadarko's Ad Valorem testimony in Phase II, as well as renewed their motions to exclude Ad Valorem evidence. The Carriers' Motions were denied.[119]

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[115] *BP Pipelines (Alaska) Inc*., 139 FERC ¶ 63,007 (2012).

[116] *Id.* P 18.

[117] Tr. 207:21-25, 208:1-6 (Docket No. IS09-348-006, Vol. 2).

[118] *BP Pipelines (Alaska), Inc.*, 139 FERC ¶ 63,009, at PP 2-3 (2012).

[119] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-006, *et al.*, Order Denying Motion to Strike (June 19, 2012). The TAPS Carriers filed a Motion to Permit Interlocutory Appeal on July 2, 2012, which was denied. The TAPS Carriers filed an Interlocutory Appeal with the Commission on July 5, 2012. Chairman Jon Wellinghoff issued a Notice of Determination by the Chairman on July 10, 2012 in Docket No. IS09-348-004, *et al.* In his notice, Chairman Wellinghoff, acting as Motions Commissioner, concluded TAPS Carriers failed to demonstrate extraordinary circumstances. Therefore, the Chairman did not refer the TAPS Carriers' Interlocutory Appeal to the full Commission.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

80. The Carriers filed their rebuttal testimony for Phase I on June 4, 2012. Anadarko and State filed deposition notices and served supplemental data requests related to the June 4, 2012 rebuttal testimony.

81. On June 19, 2012, the parties advised the Chief Judge that they had been negotiating settlement of most or all of the issues set for hearing in Phase II beginning on July 5, 2012. The Presiding Judges, RCA Commissioners, and the Chief Judge informally met with representatives of each party to discuss the possibility of settlement and whether the settlement activities had been successful enough to warrant postponing the Phase II hearing through July to allow the parties more time to work on a settlement agreement. Based upon the representations of all parties at the informal meeting on June 20, 2012 in Washington, DC, Chief Judge Wagner postponed the Phase II hearing to allow the parties more time to continue settlement negotiations. The parties advised that there may be more minor issues remaining in Phase II that might need to be heard after a settlement agreement was completed but were confident the remaining issues would only take a few hearing days.

82. On June 21, 2012, Chief Judge Wagner granted the parties' request to postpone the Phase II hearing. Chief Judge Wagner gave the parties until July 23, 2012 to file a settlement agreement or advise the Chief Judge, RCA Commissioners, and Presiding Judges that a settlement in principle of the life of line issues had been reached. Chief Judge Wagner further ordered that if a settlement was not reached by July 23, 2012, the Phase II hearing would commence August 15, 2012. Chief Judge Wagner also ordered that any remaining issues in Phase II not resolved in a settlement agreement would be heard immediately following the Phase I supplemental hearing still scheduled for September 5, 2012, with the location of the Phase II hearing being equally divided between Anchorage, Alaska and Washington, DC. A decision regarding dates for briefings in each phase and for an initial decision was deferred until a later date.[120]

83. Several discovery disputes arose during the course of the supplemental discovery process in Phase I, some of which required oral argument. The TAPS Carriers were ultimately ordered to produce all documents and data requested of them by Anadarko and State and produce all witnesses noticed for depositions in a timely manner. Some of the discovery disputes were resolved by the parties during oral arguments without the need for the Presiding Judges to rule.[121] The TAPS Carriers filed a Motion for Expedited

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[120] *BP Pipelines (Alaska) Inc., et al.*, Docket Nos. IS09-348-004, *et al.* and IS09-348-006, *et al.*, Order of Chief Judge Confirming Rulings, Rescheduling Phase II Hearing, and Establishing Additional Procedures (June 21, 2012).

[121] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order Confirming Rulings (July 16, 2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Clarification of Discovery Rulings. The Motion for Clarification was denied on July 24, 2012.

84. On July 23, 2012 the parties emailed the Presiding Judges, RCA Commissioners, and Chief Judge Wagner to advise they had reached a settlement in principle of the depreciation/life of line issues set for hearing in Phase II and planned on filing a settlement agreement by August 24, 2012 or advising the Commissions of the status of a settlement agreement at that time. The email also indicated that the parties planned to continue to negotiate settlement of the issues still remaining in Phase II.

85. Anadarko filed a motion to strike portions of Carrier's pre-filed rebuttal testimony, or for alternative relief on July 9, 2012. An oral argument on the motion was held on July 27, 2012. At the oral argument a procedural schedule for the remaining hearing was also discussed. The Presiding Judges issued an order on July 31, 2012. The order denied Anadarko's motion to strike portions of the Carrier's pre-filed rebuttal testimony and partially granted Anadarko's motion for alternative relief. The order permitted Anadarko to file answering testimony to Carriers' pre-filed rebuttal testimony by August 10, 2012 and also to call their witnesses to testify at the supplemental Phase I hearing. The order also provided Carriers' the opportunity to file reply testimony by August 24, 2012. Finally, the Presiding Judges ordered Carriers to make their witnesses available at the supplemental Phase I hearing, to be followed by Anadarko's witnesses.[122]

86. At the July 27, 2012 oral argument, all parties agreed that the remaining non-life of line issues that were scheduled to be addressed at the August 15 hearing would be heard either at the end of the hearing commencing on September 5, 2012 or would be briefed to the Presiding Judges. The hearing on these issues scheduled for August 15, 2012 was therefore unnecessary and canceled.[123]

87. The Phase I supplemental hearing began in Anchorage, AK, running from September 5 to 14, 2012 and continued in Washington, DC from September 19 to 28, 2012. The Phase II hearing began again in Washington, DC on September 28 and ended on October 2, 2012.

88. The Presiding Judges ordered the participants to file a joint and complete chronology of exhibits for the prudence phase by October 30, 2012 and then submit new

[122] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order Denying Motion to Strike and Partially Granting Alternative Relief (July 31, 2012).

[123] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order of Chief Judge Canceling Hearing (Aug. 3, 2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

briefs, with the initial briefs due on November 30, 2012.[124] The participants filed their joint chronology on October 31, 2012.[125]

89. Due to the complexity of the proceedings, the Chief Judge extended the time for the filing of reply briefs beyond that prescribed by the Track III procedural time standards to January 25, 2013. The Chief Judge also deferred establishing a date for the issuance of the initial decision until the reply briefs were filed.[126]

90. On October 11, 2012, the Parties jointly submitted the Offer of Settlement for the life of line issue. The Parties also requested that the comment period be shortened so that the initial comments would be due by October 22, 2012 and the reply comments due by October 26, 2012. This request was granted.[127] Staff filed comments on October 22, 2012 supporting the settlement. On November 13, 2012, the parties and Staff filed a Consent Motion for Clarification to the Agreement, which clarified the identity of the Carriers and their obligations after January 1, 2013, in light of the notifications by Koch and Unocal of their withdrawal from TAPS effective August 1, 2012. On November 15, 2012, Judge Cintron certified the Offer of Settlement together with the Consent Motion for Clarification as a partial settlement, as the settlement agreement did not address all issues needed to terminate the dockets under which the Offer of Settlement was filed.[128] FERC approved the partial settlement on December 28, 2012.[129]

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[124] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order Establishing Schedule for Briefing and Other Submissions (Oct. 4, 2012).

[125] The joint chronology was filed one day past the date specified by the Presiding Judges because the FERC was closed on October 30, 2012 due to severe weather conditions.

[126] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-004, *et al.*, Order of Chief Judge Establishing Reply Brief Date and Deferring Initial Decision Deadline (Oct. 4, 2012).

[127] *BP Pipelines (Alaska) Inc., et al.*, Docket Nos. IS09-348-006, *et al*., Order Granting Motion for Shortened Comment Period (Oct. 15, 2012).

[128] *BP Pipelines (Alaska) Inc., et al.*, 141 FERC ¶ 63,012, at P 2 & n.2 (2012).

[129] *BP Pipelines (Alaska) Inc., et al.*, Docket No. IS09-348-009, *et al.*, Letter order approving Settling Parties' October 11, 2012 filing of a Partial Settlement Agreement resolving the depreciation and thereby the life of line issues under IS09-348 *et al*., 141 FERC ¶ 61,263 (Dec. 28, 2012).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

91. The Carriers, Anadarko/Tesoro, Staff, the State, and Flint Hills filed new initial briefs on November 30, 2012, and the same participants filed reply briefs on January 25, 2013.[130]

IV. ISSUES

A. Issue 1: Prudence

92. At issue is whether the Carriers prudently incurred the costs of the SR project. If the costs are prudently incurred then they can be included in rates. However, even if the costs were prudently incurred, the used and useful or other ratemaking principles may bar recovery of these costs in rates.

i. Prudence: Legal Standards

93. Underlying the prudence doctrine are *Bluefield Water Works* and *Missouri ex rel. Southwestern Bell Telephone Co.*, where the Supreme Court prohibited regulated entities from recovering through rates "obviously wasteful or imprudent expenditures."[131] The rationale is that including imprudently incurred costs in rates would make those rates unjust and unreasonable.[132]

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[130] An Order issued on January 10, 2013, to allow the State to correct page 1 of exhibit SOA-172. On February 8, 2013, the Chief Judge issued an order stating that settlement procedures would not serve any purpose. On February 11, 2013, the Chief Judge by order established June 25, 2013 as the initial decision date. Staff's motion to file a cross-reference index to exhibits cited in its briefs was granted by order dated February 14, 2013. A similar motion by the TAPS Carriers was granted by order dated February 19, 2013. The State filed a similar motion which was granted on February 20, 2013. An Order re-opening the record, admitting exhibit J-2 (joint chronology of exhibits) and closing the record was issued on April 3, 2013. The Chief Judge by order dated June 25, 2013 extended the initial decision date to October 31, 2013. The initial decision date was extended to February 28, 2014 by order issued October 30, 2013.

[131] *Missouri ex rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n of Missouri*, 262 U.S. 276, n.1 (1923) (Brandeis, J., dissenting). *See also Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 693 (1923) ("The return . . . should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

[132] *See Anaheim, Riverside, Banning, Colton and Azusa, Cal. v. FERC*, 669 F.2d 799, 809 (D.C. Cir. 1981). Utilities should be permitted to charge rates which are compensatory of the full cost incurred by alert, efficient, and responsible management, but customers should not be required to pay more than this cost. *Midwestern Gas Transmission Co*., 36 F.P.C. 61, 99 (1966).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

94. If an expenditure is prudently incurred, its recovery in rates may still be barred under the used and useful standard. The used and useful standard helps balance the Commission's obligation to ensure just and reasonable rates and the Fifth Amendment takings clause. In *Denver Union Stock Yard Co.*, the Court wrote "[a]s of right safeguarded by the due process clause of the Fifth Amendment, appellant is entitled to rates, not per se excessive and extortionate, sufficient to yield a reasonable rate of return upon the value of property used, at the time it is being used, to render the services. But it is not entitled to have included any property not used and useful for that purpose." *Denver Union Stock Yard Co. v. United States*, 304 U.S. 470, 475 (1938) (citations omitted). The Court also cautioned that the Fifth Amendment does not provide utility investors with a haven from the operation of market forces. *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 590 (1942) ("Regulation does not insure that the business shall produce net revenues.").

The Legal Standard for Prudence

95. All participants agree that the substance of the Commission's prudence standard is governed by the *New England Power Co*. reasonable manager test.[133] Procedurally, participants agree that costs are presumed prudently incurred until those challenging them (the State and Anadarko), raise serious doubt as to the prudence of the actions leading to the costs at issue. Participants also agree that the burden then shifts to the rate proponents (the Carriers) to dispel these doubts with specific evidence showing that the expenditures were prudent.

96. However, participants dispute the requirements for raising serious doubt and whether these have been satisfied. Participants also dispute the scope and substance of the reasonable manager test, in particular, what is being evaluated under prudence, what reasonableness entails, what information may form the basis of a prudence evaluation, the role of good faith and intent, and the degree alternatives must be considered. Participants dispute whether the Carriers' affiliate relationships require heightened scrutiny. Lastly, once the presumption of prudence has been lifted, participants dispute whether the Carriers have satisfied their burden to demonstrate with specific evidence the prudence of their expenditures to be included in rates.

Extent of evidence needed to lift the presumption of prudence

97. Participants agree that the Carriers rates are presumed prudent until the State and Anadarko (collectively, Challengers) raise a serious doubt as to the prudence of the SR

[133] State IB 130; Staff IB 48; Anadarko IB 19; Carriers IB 84, 86 (citing *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985); *aff'd sub nom., Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

expenditures, but dispute what "serious doubt" entails and whether Challengers have satisfied it. The Challengers and Staff assert serious doubt has been cast on the cost of the SR project, relying largely on the May 1, 2012 Order on Burden of Proof[134] and the clarification during hearing on October 2, 2012. Tr. 9142-43, 9155-56. Anadarko IB 27; Staff IB 5, 47; State IB 132. The Carriers contest this assertion, arguing that order, by its terms, was not a determination of serious doubt. Carriers IB 85.

98. According to the Carriers, establishing serious doubt requires "reliable, probative and substantial evidence" of imprudence.[135] The Carriers aver that both the serious doubt and the ultimate prudence determination require two inquiries: (1) whether the Carriers engaged in imprudent conduct; and (2) if imprudent conduct is found, whether it caused the incurrence of excessive costs. Carriers contend that a showing of serious doubt is a heavy burden, requiring the Challengers to show causation between alleged imprudent action and allegedly excessive costs resulting from such actions (or injury**)** for each specific cost challenged. Carriers IB 86, 213-15; RB 14. No participant disputes that some causal relationship must exist between the alleged imprudence and the rate increase to shift the burden.

99. The State, asserts that a challenging party need not show a "one-to-one link" between each alleged imprudent action and the particular costs of each action, but that showing a causal connection or nexus between imprudent actions and the cost increases incurred by the regulated company is sufficient.[136] The State argues that it has satisfied these requirements. State RB 7 ("Had the TAPS Carriers not imprudently sanctioned the SR project, they would not have incurred its costs."); *id*. at 9 ("Because the TAPS Carriers imprudently decided to pursue Electrification, they incurred increased costs—the costs of that project. If they had not pursued Electrification, they would not have incurred those costs."). The State also notes that the evidence regarding expenditures is in the Carriers possession and not the parties challenging them, and the extent of evidence necessary to shift the burden cannot be so extensive that it effectively reverses the statutory burden of proof.

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[134] Order on Burden of Proof, *BP Pipelines (Alaska) Inc*., Docket No. IS09-348-004, *et al.* (May 1, 2012) (Order on Burden of Proof).

[135] Carriers IB 85 (citing *Cal. Indep. Sys. Operator Corp*., 99 FERC ¶ 63,020, at 65,075 (2002); *Wis. Elec. Power Co*., 73 FERC ¶ 63,019, at 65,225-26 (1995)).

[136] State RB 8 (citing *In re. the Application of KCP&L Greater Mo. Operations Co. for Approval to Make Certain Changes in Its Charges for Elec. Serv.*, 2011 WL 1827253, at *26 (Mo. P.S.C., May 4, 2011) (No. ER-2010-0356) (stating that the protestant must only "establish[] a causal connection or 'nexus' between the alleged imprudent action and the costs incurred")).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

100. Participants dispute the required specificity of the challenged costs. Participants argue that the sanction and execution of the SR project was imprudent, but that only some of these costs are captured in the AFEs. State witness Frank Adams testified that "[c]ost data was not recorded and tracked by Alyeska or the TAPS Carriers based on each event, action, or issue that involved the project. Therefore, quantifying each and every imprudent decision is not possible with any reasonable degree of accuracy." State RB 10-11 (citing Ex. SOA-546 at 26:1-15, F. Adams Reply Test.). (Note, however, that "there is no question as to the identity of the costs . . . tracked through Alyeska's AFE system. Additionally, the State detailed the subset of increased Electrification costs that the TAPS Carriers incurred because of their mismanaged execution of Electrification." State RB 9.) The Carriers argue that the Challengers must demonstrate serious doubt with greater specificity and that the challenge must be targeted at specific cost items.[137] The Carriers contend that establishing serious doubt about the prudence of a specific action within the SR project would shift the burden to the Carriers to justify only the increased costs resulting from that particular action, not all SR project costs. Carriers RB 10. The State disagrees with this position. The State RB 10.

101. Staff notes that the presiding judges have already found that Challengers have raised serious doubts as to the prudence of the planning, implementation, management and oversight of the SR Project. Staff asserts that Challengers have presented specific, detailed allegations of imprudent conduct through witness testimony based on decades of personal experience and expertise in project management, pipeline and turbine engineering, and ratemaking issues. According to Staff, the evidence shows that the Carriers failed to follow basic pipeline industry practice as well as their own internal protocols in their planning, management, implementation, and oversight of the SR Project. Staff IB 47.

Discussion/Findings

102. Fundamentally, the burden of proof of demonstrating that proposed oil pipeline transportation rates are just and reasonable is on the carrier. Interstate Commerce Act (ICA) §§ 1(5), 15(1), 49 U.S.C. App. §§ 1(5), 15(1) (1988); *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1501 (D.C. Cir. 1984) ("[A]ll rates charged for oil pipeline transportation 'shall be just and reasonable'" under ICA section 1(5), "under section 15(1), Congress authorized FERC 'to determine and prescribe what will be the just and reasonable' rate for such transportation services."). ICA § 15(7), 49 U.S.C. App. § 15(7) ("the burden of proof shall be upon the carrier to show that the proposed changed rate . . . is just and reasonable."). It is worth noting that the Natural Gas Act (NGA) and the

[137] The Carriers cite to *Medina Power Co.* to support their contention that the challenge must be targeted at specific items of cost. But the challengers in *Medina Power Co.* only challenged certain costs of a project, but did not specify which ones. *Medina Power Co.*, 76 FERC ¶ 63,013, at 65,057-59 (1996).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Federal Power Act (FPA) impose the same burden on natural gas companies and utilities and courts have relied on cases interpreting one act to decide cases under another.[138] Judicial and FERC precedent uphold these statutory mandates imposing the burden of proof on the applicant to show its rates are just and reasonable,[139] and rates are not just and reasonable if they include imprudently incurred expenditures.[140]

103. However, as a matter of procedural practice to ensure that rate cases are manageable, the Commission does not require regulated entities to demonstrate in their cases-in-chief that all expenditures were prudent.[141] The proposed rates are presumed just and reasonable, but this presumption does not survive "a showing of inefficiency or improvidence"[142] and may be rebutted when a participant creates a "serious doubt" as to the prudence of an expenditure.[143] The extent of evidence necessary to establish a serious doubt needs to be more than a "bare allegation of imprudence" but "cannot be so extensive that it in effect reverses the statutory burden of proof." This is important because "the evidence regarding any expenditure is in the hands of the utility and not the

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[138] "[T]he burden of proof to show that the rate or charge is just and reasonable shall be upon the natural gas company." NGA § 4, 15 U.S.C. § 717c(e). "[T]he burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility." FPA § 205(e). The D.C. Circuit has "recognized the similarity between the operative language of §§ 15(7) and 15(1) of the ICA and of §§ 4 and 5 of the NGA and have relied on cases interpreting one act to decide cases under the other." *Flint Hills Res. Alaska, LLC v. FERC*, 627 F.3d 881, 887 (D.C. Cir. 2010). The Supreme Court has held that the NGA and the FPA are "in all material respects substantially identical," *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 353 (1956), and constructions of one are authoritative for the other. *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577, n.7 (1981).

[139] *See, e.g.*, *New England Power Co.*, 31 FERC ¶ 61,047, at 61,084 (1985); *aff'd sub nom. Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986); *Iroquois Gas Transmission Sys.*, 87 FERC ¶ 61,295, at 62,169 (1999); *Williams Natural Gas Co.*, 80 FERC ¶ 61,408, at 62,344 (1997); *See also SFPP, L.P.*, 134 FERC ¶ 61,121, at P 46 (2011).

[140] *Violet v. FERC*, 800 F.2d at 282.

[141] *Anaheim, Riverside, Banning, Colton, & Azusa, Cal. v. FERC*, 669 F.2d 799, 809 (D.C. Cir. 1981); *Iroquois Gas Transmission Sys., L.P.*, 87 FERC at 62,168 (citing *Minn. Power & Light*, 11 FERC ¶ 61,312, at 61,645 (1980)).

[142] *Anaheim, Riverside, Banning, Colton, & Azusa, Cal.*, 669 F.2d at 809 (citing *W. Ohio Gas Co. v. Pub. Utils. Comm.*, 294 U.S. 63, 72 (1935)).

[143] *Minn. Power & Light Co.*, 11 FERC at 61,645.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

parties challenging the expenditure."[144] Once a participant in the proceeding "creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent."[145] To meet the burden of proof in demonstrating the prudence of the expenditure, the applicant must make an affirmative defense and produce specific evidence justifying the challenged expenditure.[146]

104. How the burden shifts in a prudence determination can be summarized as follows. The rate proponent has the ultimate burden of proving that each element of its proposed rates is just and reasonable. In the absence of evidence to the contrary, these costs are presumed to be prudently incurred. However, the presumption of prudence does not survive a showing of inefficiency or improvidence, and where some other participant in the proceeding creates serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent. Thus, the burden of going forward with evidence of imprudent conduct falls upon the challengers of the rates. If this burden is met, the presumption of prudence dissolves and the rate proponent bears the ultimate burden to

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[144] *Iroquois Gas Transmission Sys., L.P.*, 87 FERC at 62,168-69 (citing *Minn. Power & Light*, 11 FERC at 61,645).

[145] *Anaheim, Riverside, Banning, Colton, & Azusa, Cal.*, 669 F.2d at 809; *Iroquois Gas Transmission Sys., L.P.*, 87 FERC at 62,168; *Williams Natural Gas Co.*, 80 FERC at 62,344; *Minn. Power & Light Co.*, 11 FERC at 61,645. *See also Entergy Servs., Inc.*, 130 FERC ¶ 61,023, at P 52 (2010) ("a challenger to prudence must create a 'serious doubt' as to the prudence of an expenditure; however, once that serious doubt is created, the burden shifts to the applicant to demonstrate that the expenditure in question was prudent.").

[146] *Iroquois Gas Transmission Sys., L.P.*, 87 FERC at 62,168–69 (citing *Anaheim, Riverside, Banning, Colton, & Azusa, Cal.*, 669 F.2d at 809 (the Court affirmed the Commission decision that the burden shifted to the utility to demonstrate the prudence of its abandonment of a facility, because a state public service Commission disallowed the expense (the state Commission had not ruled on the merits of the utility's conduct, and disallowed the expense only because the utility procedurally had not justified the prudence of the expense in the state proceeding). The Court affirmed the Commission that the utility had not met its burden of proof, because it relied only on vague generalizations, but failed to "come forward with specific evidence" to justify the expense) and *Minn. Power & Light*, 11 FERC at 61,645). *See also Pub. Serv. Co. of N.H.*, 6 FERC ¶ 61,299, 61,710-11 (1979) ("Once the complainants . . . have presented a prima facie case for relief, the burden shifts to the respondent to make an affirmative defense.").

20140227-3052 FERC PDF (Unofficial) 02/27/2014

show that its actions were prudent. *See, e.g.*, *Trunkline LNG Co., Trunkline Gas Co.*, 45 FERC ¶ 61,256, at 61,775 (1988).

Evidence needed to establish serious doubt

105. To cast serious doubt on an expenditure, the extent of evidence needs to be more than a "bare allegation of imprudence" but "cannot be so extensive that it in effect reverses the statutory burden of proof," because "the evidence regarding any expenditure"[147] is in the hands of the rate proponent. In fact, a party challenging the prudence of an expenditure may meet its burden through direct or circumstantial evidence. *Midwestern Gas Transmission Co*., 28 FERC ¶ 63,011, at 65,061 (1984). Evidence sufficient to raise serious doubt includes "intimations" of imprudence by the State public utility commissions without final merits determinations. These were sufficient to place the burden on the utilities to justify the prudence of their actions.[148] In *Enbridge Pipelines*, the Commission found that the challenging parties had shifted the burden by showing that a conflict of interest existed because a pipeline executive was simultaneously president of the consulting firm used by the pipeline, that the pipeline lacked certain information about the expenses it was seeking to recover, and that the expenses included certain improper costs. *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at PP 333, 338 (2002).

106. On the Carriers' account, the serious doubt and ultimate prudence determinations require that the Commission determine whether the Carriers engaged in imprudent conduct, and if imprudent conduct is found, whether it caused the incurrence of excessive costs. Carriers IB 86. But the Carriers proposed slicing of the burden of proof seems tautological (the prudence determination depends whether there was imprudent conduct), redundant (it addresses the same questions twice in a two-step determination), and

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[147] *Iroquois Gas Transmission Sys., L.P.*, 87 FERC at 62,168-69 (citing *Minn. Power & Light*, 11 FERC 61,645).

[148] *Iroquois Gas Transmission Sys., L.P*., 87 FERC at 62,168-69 (citing *Minn. Power & Light*, 11 FERC at 61,645 (a State regulatory agency order intimating that certain costs were imprudent was sufficient for raising a serious doubt); *S. Cal. Edison Co*., 8 FERC ¶ 61,198, at 61,679-80 (1979) (affirming the initial decision, where the presiding judge merely stated that in view of the fact that the challengers had informed Edison that they intended to rely on the State public utility commission decision to challenge an expense, Edison should have been prepared to come forward with specific evidence justifying it); *Anaheim, Riverside, Banning, Colton, & Azusa, Cal.*, 669 F.2d at 809 (affirming Commission decision shifting the burden to the utility to demonstrate prudence, where Commission decision was based on a State public service commission's disallowance of an expense due to a procedural defect in justifying the prudence of the expense).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

introduces an element of causation that is more typical for a party with the burden of proof, such as a plaintiff in a torts claim. Thus, the Carriers' attempt to raise the bar on establishing serious doubt essentially puts the ultimate burden of proof on the Challengers, which is inappropriate at the serious doubt phase. Essentially, the Challengers need only rebut a presumption.

107. The State and Anadarko, as described in detailed below, proved that the Carriers did not follow industry standards and Alyeska's engineering protocols, discarded the opinions of experienced employees and discarded years of proper studies at the time of sanction. In addition, as if this was not enough to rebut the presumption, the Challengers also established that the Carriers hired inexperienced personnel to manage the project, did not properly supervise their contractors, started the project before appropriate engineering had been completed, in contravention of industry standards, and did not ever successfully implement a management of change process, among others. This evidence was sufficient to raise serious doubt, rebut the presumption and shift the burden of proof back to the rate proponent, which had the original burden of proof.

Causation

108. Contrary to the Carriers' contention (Carriers IB 214) there is no explicit requirement to demonstrate causation and injury in order to cast serious doubt. To require the challenger to come forth with evidence demonstrating a one-to-one link between causation and injury would essentially reverse the statutory burden of proof (requiring the applicant to demonstrate that proposed rates are just and reasonable). Indeed, even the Carriers admit that SR accounting records do not split out the costs of various aspects of the project,[149] and SR expenditures are spread over a range of AFEs. Ex. AT-493. However, even accepting the Carriers' argument that causation must be demonstrated for each specific cost, the evidence in this case establishes that the Challengers succeed in raising serious doubt on all of the SR expenditures that were tracked.

109. The Carriers' attempt to introduce an element of causation into the serious doubt inquiry is not supported by their citation to *Violet v. FERC*. The *Violet* court was not introducing a new element or setting a new standard in FERC's test for prudence.[150] Instead, *Violet*'s holding is based on administrative deference: absent evidence of a causal link between the allegedly imprudent conduct and the incurred costs, the

[149] Carriers IB 227; *see also* Ex. SOA-387 at 1; Ex. SOA-279 at 5.

[150] Carriers IB 213-15, RB 14. *Violet v. FERC*, 800 F.2d 280, 283 (1st Cir. 1986) ("In the absence of more tangible evidence of a causal link between the allegedly imprudent contract and the costs NEP now seeks to recover, we cannot say that the Commission erred as a matter of law in refusing to focus on the events predating July 1, 1980.").

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Commission did not err and therefore deserved deference. This rationale is evident from the preceding paragraphs discussing the Administrative Procedure Act and the leading cases associated with agency deference.[151] In the case at bar, the Challengers have established a sufficient casual connection between the imprudent actions and the challenged costs.[152]

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[151] *Id*. at 282 ("Under the Administrative Procedure Act, we may set aside a FERC order only if we determine that it is arbitrary, capricious, an abuse of discretion, or in excess of statutory authority. 5 U.S.C. § 706(2) (1982). We thus look to see whether the decision was based on a consideration of the relevant factors and whether there has been a clear error of judgment. *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402, 416, 91 S.Ct. 814, 823-24, 28 L.Ed.2d 136 (1971). All findings of the Commission, if supported by substantial evidence, are conclusive upon us. Federal Power Act, 16 U.S.C. § 825l (b) (1982); *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 766, 88 S.Ct. 1344, 1359, 20 L.Ed.2d 312 (1968).With this deferential standard in mind, we examine the arguments made by Rhode Island.").

[152] The Carriers' reliance on *Entergy* (Carriers RB 11) is irrelevant and problematic. The Carriers' allegation is problematic because it appears to conflate two different *Entergy* cases, (a 1993 decision and a 2010 decision) and takes out of context the statement about flawed decision-making in the 1993 *Entergy* case. In the 1993 *Entergy* case the presiding judge ruled that Entergy failed to adequately make pre-transfer studies for the spinoff, thus "raising serious questions about the company's decision-making process." *City of New Orleans v. Entergy Corp*., 65 FERC ¶ 61,333, at 62,564 (1993). But because the overall outcome was reasonable, the judge found the ultimate decision prudent notwithstanding the flawed decision-making. Thus, the Carriers' assertion that flawed decision-making was not sufficient to establish serious doubt in *Entergy* is inaccurate. In this case, where the forecasted costs have tripled and project completion is almost a decade behind schedule, the overall outcome does not render any flawed decision-making irrelevant. Staff RB 13.

The 2010 *Entergy Services* case also does not support the Carriers' contention. In that case, FERC affirmed the presiding judge's conclusion that the Louisiana Commission failed to cast serious doubt on the prudence of Entergy's conduct, and that even had the Louisiana Commission created a serious doubt, the record supports the finding that Entergy's decision not to repurchase the ISES 2 capacity was prudent at the time it was made. *Entergy Servs., Inc.*, 130 FERC ¶ 61,023, at PP 53-54 (2010). In particular, the Louisiana Commission raised after-the-fact arguments and did not use the appropriate standard (i.e., *New England Power Co.*). *Id*. PP 54, 57. FERC found that Entergy had a strategic plan with which it evaluated the ISES 2 option and weighed it against other alternatives. It had previously owned and operated the ISES 2 unit and was familiar with the costs and operating characteristics of the unit, which had higher costs than other alternatives identified in the strategic plan, according to Entergy's expert

20140227-3052 FERC PDF (Unofficial) 02/27/2014

The required degree of specificity in costs

110. *The New England Power Co*. test contemplates "the prudence of specific costs," and this is evaluated at "the relevant point in time." The relevant point in time is when the challenged costs were incurred or committed to be incurred. All related expenditures incurred at the same time may be evaluated together. Evaluating the prudence of expenditures by that specified in the AFEs, or any other documents tracking expenses, would conform to the *New England Power* test as it is usually applied, but this would mean that any costs not tracked would not be evaluated in the prudence determination. Leaving these costs outside the scope of the prudence determination would provide an incentive for the Carriers to render their accounting less transparent and more difficult to challenge.

111. Clearly, there must be a balance between requiring too much and too little specificity. A greater degree of specificity of costs required increases the burden imposed on the challengers to establish serious doubt, because the evidence regarding any expenditure is under the control of the Carriers. Thus, requiring too much specificity may effectively reverse the statutory burden of proof. On the other hand, it would be unfair to allow for a relatively lax requirement in demonstrating serious doubt to trigger the Carriers' responsibility to come forth with specific evidence, which could be a substantial burden for a large project.

112. Even though it is the Carriers who are in control of the evidence and face a disincentive for transparency, the direct application of the *New England Power Co*. test is to evaluate the specific costs identified in the AFEs. It is noted that there is a potential universe of SR costs not tracked in the AFEs, but as they are not in the record, those cannot be evaluated.

113. The Carriers' contentions that serious doubt has not been cast on SR expenditures, and that there was no explicit determination of serious doubt are without merit. The Challengers have satisfied the requirements to shift the burden, as stated in the May 1, 2012 Order on Burden of Proof and made explicitly clear in a clarifying bench ruling during hearing on October 2, 2012.[153] The law does not dictate that the substance of the serious doubt finding be spelled out in an interim ruling in order to lift the presumption of

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witness. *Id.* P 56. FERC also found that the evidence demonstrated that market conditions at the time strongly cautioned against Entergy's acquisition of the ISES 2 capacity. *Id*. P 58. Here, in contrast, the Carriers did not have a good understanding of the costs and the economics of the project did not weigh in its favor.

[153] The Carriers have filed no pleadings whatsoever seeking relief or clarification from either ruling, much less any pleading within a reasonable time period. *See* 28 U.S.C. § 60(c)(1) (2006). Thus, their contentions regarding the burden of proof issue are without procedural as well as substantive grounds.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

prudence. A bench ruling and order shifting the burden suffice here. The Carriers were fully aware of which costs were being challenged and were on notice that they must provide evidence demonstrating that the costs challenged in the proceeding were prudently incurred. The record existing at that time of the ruling (including testimony, hearing transcripts, and post-hearing briefs on the prudence issue) was enough to support that serious doubt had been cast on the prudence of Carriers SR expenditures. The record as supplemented since May 1, 2012 contains substantial evidence that serious doubt has been cast on the SR expenditures. The Carriers have been on notice at least since the May 1, 2012 Order on Burden of Proof, if not before, that serious doubts have been cast on SR project expenses, and that it was their burden to dispel the doubts and justify the prudence of the incurred SR project costs. *See also* Tr. 9155-56.

114. The point of reopening the record to allow the Carriers to file additional testimony was to cure any potential procedural defect associated with "confusion" over the Carriers having the ultimate burden of proof and to give the Carriers an additional opportunity to dispel the serious doubts raised on SR project costs and affirmatively prove that the SR project was prudent (the sanction, management and execution). *See Iroquois Gas Transmission Sys.*, 79 FERC ¶ 63,020, at 65,192 (1997) (the party with the burden of proof has the "customary right of final rebuttal"); 1 Clifford S. Fishman & Anne T. McKenna, Jones on Evidence § 3.44 (7th ed. 2011) ("as a general rule [the right to open and close] belongs to the party with the ultimate burden"). It is the ultimate hubris, for the Carriers to accept the procedural remedy premised on the fact that they have the ultimate burden of proof to dispel serious doubt, and now take the position that serious doubt has not been raised, after having the advantage of filing an additional round of testimony.

The Commission's prudence standard and its scope

115. Participants have differing views on the scope of the prudence determination. Staff alleges that the Carriers were not prudent in the "development, planning, design, management and implementation" of the SR Project, and that ratepayers should not bear the cost of the Carriers' imprudence. Staff IB 3. The Carriers more narrowly characterize the scope as their decision to pursue electrification instead of hybrid and their management and oversight of the SR project. Carriers IB 86-87. The Carriers' aver that when investment decisions are at issue, the principal focus is whether management took the steps reasonably necessary to make an informed decision, whether management reasonably considered ratepayer concerns, and whether management reasonably weighed the risks versus the rewards of the project.[154] The Carriers assert that when project management is at issue, the principal questions are whether a reasonable process was put

[154] Carriers citing *New England Power Co.,* 75 FERC ¶ 63,004 at 65,015 (1996)); *Iroquois Gas Transmission Sys.*, 87 FERC ¶ 61,295 at 62,170 (1999); *Ky. Utils. Co*., 62 FERC ¶ 61,097 at 61,709 (1993)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

into place by management, and whether management responded reasonably based on the facts and circumstances as they developed.[155] Staff asserts that the Commission considers all facts and circumstances in making a prudence determination, rather than relying on more specific bright-line rules. Staff IB 49. The State agrees that the test for prudence is not so limited. State RB 111.

116. Participants disagree on the substance of the reasonable manager prudence standard, in particular, what reasonableness entails, what information may form the basis of a prudence evaluation, the role of good faith and intent, and the degree alternatives must be considered.[156]

117. The Carriers are the lone participants who disagree that prudence is determined based on what the pipeline knew or should have known.[157] Instead, the Carriers contend that prudence must be analyzed based only on information that the pipeline possessed at the relevant time, not on what the pipeline should have known. Carriers RB 13. The Carriers note that the Commission should not, using the benefit of hindsight, replace the business decisions of a utility with its own. The State agrees that while the use of hindsight is impermissible under the prudence standard, management decisions must be analyzed based not only on the information that the pipeline possessed at the relevant time but also upon the information that pipeline should have reasonably known at that time. Relatedly, the Carriers argue that documents created after the fact cannot be used in the prudence determination. The State points out that information that was known at the time of the decision contained in documents created after the fact may be used. State RB 18.

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[155] Carriers citing *Conn. Yankee Atomic Power Co.*, 113 FERC ¶ 63,026, at 63,033-47; *see also Union Elec. Co. & Mo. Edison Co., 21 FERC* ¶ 63,080, at 65,232 (1982); *El Paso Natural Gas Co.*, 57 F.P.C. 989, 1014 (1977)).

[156] The Carriers correctly note that pipeline and other "utility managers have broad discretion in conducting their business affairs," and "there exists a range of prudent decision making." *Ky. Utils. Co.*, 62 FERC at 61,695. The Carriers point out that management need not have "clairvoyance" and it is not held to a "hypothetical ideal." *Canal Elec. Co*., 57 FERC ¶ 63,016 at 65,098 (1991); *Iroquois Gas Transmission Sys*., 87 FERC ¶ 61,295, at 62,167 (1999). The Carriers also state that while regulated entities have an obligation to serve their customers, they cannot be expected to guarantee favorable outcomes when undertaking major projects, and the fact that a project has experienced cost or schedule overruns alone does not establish that management's decision-making process was imprudent. *Conn. Yankee Atomic Power Co*., 113 FERC ¶ 63,026 (2005) (nearly doubling of cost estimate did not establish imprudence); *Medina Power Co.*, 76 FERC ¶ 63,013 at 65,057-58 (1996).

[157] Anadarko IB 20-21; State IB 130; Carriers RB 12-13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

118. No participant disputes that a reasonable manager would have considered alternative actions and evaluated their costs and benefits. Staff asserts the prudence of an expenditure is assessed on whether the Carriers failed to consider the costs and benefits before undertaking that action.[158] The Carriers acknowledge that whether management reasonably weighed the risks versus the rewards of the project is relevant to prudence.[159] Staff notes that costs reasonably incurred to provide service will only be deemed prudent if undertaken for the primary benefit of ratepayers, not shareholders.[160] The Carriers point out that the Commission does not look for a single correct result or require that every possible alternative be evaluated.[161]

119. The Carriers argue that that incentives and intent are encompassed within the "good faith" language in the reasonable utility manager standard and are relevant to a prudence inquiry. Carriers IB 89 (citing to *Ky. Utils. Co*., 62 FERC ¶ 61,097, at 61,695 (1993) (The Commission noted that "the presiding judge framed the basic issue in [the] case as largely one of intent" and affirmed the presiding judge's initial decision)). The State and Anadarko suggest that intent and incentives are irrelevant. State RB 12; Anadarko RB 18 (citing *City of New Orleans v. Entergy Corp.*, 61 FERC ¶ 63,007, at 65,009 (1992) "[w]hether [the utility] was motivated purely by a desire for profit, purely by a desire for peace, or by some combination of the two, is irrelevant. The question is whether the overall result was reasonable. . . . A noble motive cannot convert an unreasonable decision, or outcome, into a reasonable one.").

Discussion/Findings

120. All participants agree that the governing prudence standard is that provided in *New England Power Co*.:[162]

> [T]o determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management . . . would have made, in good faith, under the same circumstances, and at the relevant point in time. We note that while in hindsight it may be clear that a management decision was wrong, our task is to review the prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing either at the time the challenged costs were actually

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[158] Staff RB 82 (citing *Entergy Servs*., 130 FERC ¶ 61,023, at P 52 (2010)).

[159] Carrier IB 87 (citing *Ky. Utils. Co*., 62 FERC ¶ 61,097, at 61,709 (1993)).

[160] *Iroquois Gas Transmission Sys*., 87 FERC ¶ 61,295 at 62,170 (1999).

[161] *Dakota Gasification Co.*, 77 FERC ¶ 61,271 at 62,154 (1996).

[162] State IB 130; Staff IB 48; Anadarko IB 19; Carriers IB 84, 86.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> incurred, or at the time the utility became committed to incur those expenses.

New England Power Co., 31 FERC ¶ 61,047 at 61,084 (1985); *aff'd sub nom*. *Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986); *Entergy Servs*., 130 FERC ¶ 61,023 at 61099 (2010) (affirming the applicability of the *New England Power Co*. standard.).

121. The Commission's prudence determination is "intensely fact-based"[163] and "involves a broad-ranging inquiry" into the judgment of a pipeline in incurring costs.[164] Thus, the "Commission and the courts have evaluated the prudence of regulated costs on a case-by-case basis and have applied rather general criteria in doing so."[165] The Carriers' more narrow characterization of the prudence inquiry (Carrier IB 87) is inconsistent with this precedent. While the questions specified by the Carriers are relevant and helpful to consider, none of our cases indicate that the prudence determination is limited to these inquiries. Thus, the Carrier proposed questions are exemplary but not exclusive.

The reasonable manager test

122. As detailed below, a reasonable manager should ensure that expenditures are prudently incurred at sanction by: (1) adequately researching the project before sanctioning it; (2) estimating project costs with reasonable accuracy and weighing them against project benefits to the ratepayers; and (3) adequately considering alternatives to the project.

123. **A reasonable manager would adequately conduct the relevant studies prior to project sanction.** By adequate, the managers must ensure the studies are conducted in conformance with industry standards.[166] As a corollary to the requirement that reasonable management must be adequately informed in making decisions,[167] the

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[163] *Ky. Utils. Co.*, 62 FERC ¶ 61,097 (1993) at 61,692.

[164] *El Paso Natural Gas Co*., 78 FERC ¶ 61,318, at 62,360 (1997).

[165] *New England Power Co*., 31 FERC ¶ 61,047, at 61,084 (1985); *aff'd sub nom.*, *Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986). Adjectives used in prudence cases to discuss imprudent costs include, but are not limited to "extravagant," "unnecessary," "inefficient," and "improvident." *Id.*

[166] The Carriers agree that how other similarly situated managers in the industry would act would factor into a reasonableness determination. Carriers IB 87-88.

[167] This includes gaining adequate understanding of and documenting regulatory requirements. *See Union Elec. Co*., 40 FERC ¶ 61,046, at 61,125 (1987).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

prudence of an investment must be analyzed based on what management knew or reasonably should have known. *Panhandle E. Pipe Line Co. v. FERC*, 777 F.2d 739, 745 (D.C. Cir. 1985) (upholding finding of imprudence based on what the pipeline "knew or should have known"); *Violet v. FERC*, 800 F.2d 280, 282 (1st Cir. 1986) ("The prudence of the investment must be judged by what a utility's management knew, or could have known, at the time the costs were incurred."). Inherent in reasonable decision-making is conducting adequate due diligence prior to committing resources, and this entails that management cannot simply base decisions on what it knew, but what "alert, efficient and responsible management"[168] knew or should have known or found out. Indeed, the Carriers acknowledge that the reasonable manager test includes whether management took the steps necessary to make an informed decision,[169] and this would include finding out everything it should know prior to making a decision.

124. The Carriers' position that prudence must be analyzed based only on information that the pipeline possessed at the relevant time is inconsistent with the reasonable manager's duty to conduct the relevant studies prior to project sanction. Further, none of the Carriers' arguments indicate that the law confines the Commission to evaluating the Carriers' actions based on only what they knew and not on what they should have known through due diligence as reasonable managers.

125. Particularly unpersuasive are the Carriers' arguments that take language from cases out of context. The Carriers state that the "Commission cannot base its assessment 'on facts that were not known at the time the decisions were made.'"[170] But the full sentence cited by the Carriers states that the Commission cannot base its assessment "on facts that were not known at the time the decisions were made to enter into the Settlement Agreements."[171] The omitted text makes a difference; settling adversarial parties have the incentive to ferret out information material to their mutually agreed upon decision, but the Commission must more carefully scrutinize a decision unilaterally taken by one party that could adversely affect others. While settling parties are likely to find out what they should know, the Commission must ensure that a party acting unilaterally arrived at its decision through a process that took into account what a reasonable manager should have known or found out in making the decision.

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[168] *New England Power Co.*, 31 FERC ¶ 61,047 (1985), *aff'd sub nom.*, *Violet v. FERC*, 800 F.2d 280 (1st Cir. 1986).

[169] Carrier IB 87 (citing *New England Power Co.*, 75 FERC ¶ 63,004, at 65,016 (1996)).

[170] Carriers RB 12 n.13 citing *Dakota Gasification Co.*, 77 FERC ¶ 61,271 at 62,154, 62,162.

[171] *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

126. The Carriers also state that "the FERC acknowledged its 'obligation to review the prudence of the utility's actions and the costs resulting therefrom on the basis of the particular circumstances existing at the time.'"[172] But this language, "the particular circumstances existing at the time," does not distinguish what was or should have been known at the time, and could include circumstances management reasonably should have known about but did not. In fact, in determining that the investigation was adequate, the Commission was essentially making a determination as to whether management should have known more.[173] Moreover, "on the basis of information available" language in *City of New Orleans v. FERC*[174] is also consistent with the "should have known" standard as "information *available*" to a party does not imply that they actually have it. However, available information not in possession of the decision makers nevertheless may be something they should have known.

127. The information used in assessing prudence can be derived from documents created after the investment decision was made, to the extent this information was known or should have been known at the time the decision was made. The Carriers, citing to *Northwest Pipeline Corp.,* contend that prudence cannot be evaluated on the basis of the statements in documents created after the fact. But *Northwest Pipeline Corp.* did not categorically prohibit information from documents created after the fact altogether; the Commission objected to the contents of the document because it reflected after-the-fact analyses and conclusions not based upon knowledge and circumstances existing at the time the decision was made.[175]

128. To be clear, basing the prudence determination on what a reasonable manager should have known does not mean management may be "second-guessed based on later occurrences,"[176] which is impliedly impermissible in the *New England Power Co*. test as

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[172] *See* Carriers RB 12 n.13, 14 n.16 (citing *Ky. Utils. Co*., 62 FERC ¶ 61,097 at 61,702).

[173] In *Ky. Utils. Co.*, the Commission determined that the company had obtained adequate information on a number of potential suppliers, acted reasonably in light of accumulated information, and more rigorous investigation would have greatly increased the cost. *Ky. Utils. Co*., 62 FERC at 61,702-03.

[174] *City of New Orleans v. FERC*, 67 F.3d 947, 954 (D.C. Cir. 1995) ("prudence analysis must evaluate a utility's decision on the basis of information available to the utility at the time the decision is made," citing *New England Power Co.*, 31 FERC at 61,084).

[175] *Northwest Pipeline Corp*., 92 FERC ¶ 61,287, at 61,996-97 (2000).

[176] Carrier RB 13-14 (citing *New England Power Co*., 31 FERC at 61,084; *City of New Orleans v. Entergy Corp*., 61 FERC ¶ 63,007 at 65,016 (1992)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

an evaluation based on hindsight. For example, poor investment decisions that could have been avoided had there been additional research (consistent with industry standards) could be imprudent decisions based on what management should have known, but drawing the "wrong" conclusion based on thorough engineering studies would be second-guessing.

129. **A reasonable manager would adequately assess costs and benefits of a project before sanction.** As noted by Staff, the prudence of an expenditure depends on whether management considered its costs and benefits.[177] The Carriers acknowledge that "whether management reasonably weighed the risks versus the rewards of the project" is relevant to prudence.[178] A prerequisite to weighing the costs against the benefits is an adequate understanding of the project costs before sanction. Further, the benefits to be weighed against costs are those benefits to ratepayers, not shareholders.[179] The Commission's "primary statutory duty [is]…to protect the interests of ratepayers,"[180] and impermissibly considering the benefits to shareholders instead of ratepayers raises concerns of good faith and impermissible affiliate considerations.

130. **A reasonable manager would adequately consider alternatives of a project before sanction.** The Carriers are correct to point out that the Commission does not look for a single correct result or require that every possible alternative be evaluated. *Dakota Gasification Co.*, 77 FERC ¶ 61,271 at 62,154 (1996). In making this statement, however, the Commission emphasized "the need for well-founded decisions made in good faith."[181] Thus, while the Carriers need not consider *every possible* alternative, they

[177] Staff RB 82 citing *Entergy Servs*., 130 FERC ¶ 61,023 at P 52 (2010)). *See also Ky. Utils. Co*., 62 FERC ¶ 61,097 at 61,709 ("risks are inherent in business and imprudence is based not on the mere presence of risks but on the failure to carefully evaluate the risks and weigh them against the potential benefits").

[178] Carrier IB 87 citing *Ky. Utils. Co*., 62 FERC ¶ 61,097 at 61,709.

[179] *Iroquois Gas Transmission Sys*., 87 FERC ¶ 61,295 at 62,170 n.40 (1999) ("utility was denied recovery in rate base of $ 6.3 million covering interest during construction and repair costs resulting from the implosion of an operating unit, because the company stood to derive significant financial reward from bringing a unit online quickly") (citation omitted). The Carriers also acknowledge as relevant "whether management reasonably considered ratepayer concerns." Carrier IB 87 citing *Iroquois Gas Transmission Sys*., 87 FERC ¶ 61,295 at 62,170 (1999).

[180] Staff IB 50 citing *Office of Consumers Counsel v. FERC*, 655 F.2d 1132, 1151 (D.C. Cir. 1980).

[181] *Dakota Gasification Co.*, 77 FERC ¶ 61,271 at 62,154 (1996) ("Although we do not minimize the need for well-founded decisions made in good faith, a standard more stringent than this would unduly restrain a company's management in the conduct of its

20140227-3052 FERC PDF (Unofficial) 02/27/2014

should consider the more reasonable options and provide some rationale for selecting one option over the other. (It would be unreasonable, for example, to simply not address studies indicating that an alternative is more cost effective that the option chosen.)

131. Contrary to the Carriers' assertion, it is not simply enough to have weighed alternatives without regard for whether there was a better approach. Carriers RB 12. In support, the Carriers grossly mischaracterize *Entergy* in attributing to it that "[w]hether there might have been a 'better approach' to the decision-making process was 'irrelevant to determining whether or not Entergy was imprudent.'"[182] Taking the quoted material in context, FERC in *Entergy* was stating that the Louisiana Commission's after-the-fact suggestion that Entergy should have performed a detailed, long-term study may be the better approach, but whether that particular approach is better is irrelevant to the prudence of Entergy's decision. *Entergy Servs., Inc.*, 130 FERC ¶ 61,023 at 61,100 P 57 ("The Louisiana Commission *only now* claims that Entergy should have performed a 20-year study, as well as a more detailed, formalized study. While this may or not be a better approach to take when considering whether to purchase or sell capacity, it is irrelevant to determining whether or not Entergy was imprudent with respect to its decision.") (emphasis added). FERC does not say is that it is generally irrelevant whether there is some better approach.

132. **As to project execution, a reasonable manager would plan for contingencies; put in place a process for hiring competent managers, workers, and contractors; and periodically evaluate project progress and respond as appropriate.** Along these lines, the Carriers provided helpful examples relevant to prudence: "whether a reasonable process was put into place by management," "whether management responded reasonably based on the facts and circumstances as they developed,"[183] and whether management was "attentive to the project's progress, and aggressively pursued cost containment measures wherever there were reasonable opportunities to do so."[184] But again, this is not an exclusive list of issues pertinent to prudence. Moreover, as demonstrated below, these examples were not followed by the Carriers.

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affairs. This standard permits considerable latitude, in that the Commission, in reviewing a decision such as that made by the Pipelines in this case, does not look for a single correct result or require that every possible alternative be evaluated.").

[182] Carriers RB 12 (citing *Entergy Servs., Inc.*, 130 FERC ¶ 61,023 at 61100 PP 55-56). The quoted language is actually in P 57 of the order.

[183] Carrier IB 87 citing *Conn. Yankee Atomic Power Co.*, 113 FERC ¶ 63,026 at PP 39-153 (2005).

[184] Carrier IB 87 citing *Long Island Lighting Co.*, 71 P.U.R.4th 262, 272 (N.Y. P.S.C. 1985).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Good Faith

133. While the Carriers are correct in stating that intent and incentives are encompassed within the "good faith" language of the *New England Power Co*. standard, it does not follow that intentions and incentives consistent with ratepayers' interests is strong evidence of prudence. This is because good faith is necessary but insufficient for prudence, as is evident in the *New England Power Co.* test, which contains other factors.[185] Conversely, evidence of bad faith can be indicia of unreasonableness. This could include taking into account benefits to shareholders rather than ratepayers, or producers rather than shippers when making investment decisions to be funded by ratepayers.

Specific evidence required to overcome serious doubt and prove prudence

134. Participants do not dispute that once the Challengers have successfully shifted the burden, the party that incurred the alleged imprudent expenditure must make an affirmative showing that the expenditure was in fact prudent. Anadarko notes that once the burden shifts, the pipeline must come forth with "specific" evidence justifying "each challenged cost item." *Minnesota Power & Light Co.*, 11 FERC ¶ 61,312 at 61,645; *Union Electric*, 40 FERC ¶ 61,046 at 61,123. The State notes that to meet its burden to affirmatively establish that its rates are just and reasonable, the Carriers must use specific evidence justifying their costs and must "demonstrate convincingly that the action taken at every stage . . . was prudent." *Cleveland Elec. Illuminating Co.*, 19 FERC ¶ 63,013, 65,088 (1982); *Iroquois Gas*, 87 FERC at 62,169 (citing *Anaheim*, 669 F.2d at 809).

Discussion/Findings

135. No participant disputes that once serious doubt has been cast on the prudence of certain expenditures, the Carriers have the burden to come forth with specific evidence justifying these expenditures. This is supported by precedent: once a participant in the proceeding "creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent."[186] To meet the burden of proof in demonstrating the

[185] *See City of New Orleans v. Entergy Corp.*, 61 FERC ¶ 63,007, at 65,009 (1992) ("Whether Entergy was motivated purely by a desire for profit, purely by a desire for peace, or by some combination of the two, is irrelevant. The question is whether the overall result was reasonable. The inquiry must focus on the consequences of the spin-off decision, not on the motivation behind it. A noble motive cannot convert an unreasonable decision, or outcome, into a reasonable one."). This initial decision, however, does not state that intent and incentives are never relevant.

[186] *E.g.*, *Anaheim, Riverside, Banning, Colton, & Azusa, Cal. v. FERC*, 669 F.2d 799, 809 (D.C. Cir. 1981); *Iroquois Gas Transmission Sys., L.P.*, 87 FERC ¶ 61,295, at

20140227-3052 FERC PDF (Unofficial) 02/27/2014

prudence of the expenditure, the applicant must produce specific evidence justifying the challenged expenditure.[187] In *Alamito Co.*, applicants failed to overcome serious doubt by failing to employ experts experienced in negotiating certain contracts, failing to evaluate all potential suppliers, failing to conduct an economic feasibility study, failing to avoid unreasonable costs, and failing to recognize that a project was not economic.[188] In *Union*, applicants failed to overcome serious doubt in failing to justify cost overruns for a project caused by management's failure to coordinate and integrate the engineering and construction phases of the project and failing to document adequately increases which were caused by regulatory changes.[189] As seen below, the Carriers in this case failed in many of the same respects described by the examples just provided and have not

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62,168 (1999); *Williams Natural Gas Co.*, 80 FERC ¶ 61,408, at 62,344 (1997); *Minn. Power & Light Co.*, 11 FERC ¶ 61,312, at 61,645 (1980); *Entergy Servs., Inc.*, 130 FERC ¶ 61,023 at 61099 (P 52) (2010); *Public Serv. Co. of N.H.*, 6 FERC ¶ 61,299, 61,710-11 (1979).

[187] *Iroquois Gas Transmission Sys., L.P.*, 87 FERC ¶ 61,295, at 62,168–69 (citing *Anaheim, Riverside, Banning, Colton, & Azusa, Cal. v. FERC*, 669 F.2d 799, 809 (D.C. Cir. 1981) (affirming that the utility had not met its burden of proof, because it relied only on vague generalizations about the problems inherent in all building projects, but failed to "come forward with specific evidence" justifying expenditure)); *Minn. Power & Light*, 11 FERC ¶ 61,312, at 61,645 (1980); *Union Elec.*, 40 FERC ¶ 61,046, at 61,123.

[188] In *Alamito Co.*, the Commission held that Alamito failed to overcome serious doubts about the costs incurred under a coal contract, because the utility failed to employ experts experienced in negotiating coal contracts, failed to evaluate all potential sources of suitable coal, failed to conduct an economic feasibility study, failed to protect itself from unreasonable transportation costs, and failed to recognize it was not economic to construct a rail spur to get the coal to the plant. *Alamito Co.*, 46 FERC ¶ 61,389 (1989).

[189] In *Union Elec.*, the State commission found that cost overruns for the Callaway project were caused by Union's failure to coordinate and integrate adequately the engineering and construction phases of the project, and that Union failed to document adequately increases which were caused by regulatory changes. *Union Elec.*, 40 FERC ¶ 61,046, at 61,124. Union was unable to overcome serious doubt and prove that these costs were prudently incurred. *Id.* at 61,126. *See also Nat'l Fuel Gas Supply Corp.*, 44 FERC ¶ 61,293, at 62,055-58 (1988) (finding that National Fuel imprudently purchased gas to make off-system sales resulting in net detriment to on-system customers when nothing in the record indicated that the purchase was necessary); *Williams Natural Gas Co.*, 80 FERC 61408, 62,337 (1997) (finding it imprudent to enter into contracts which did not comport with Williams' gas purchasing policies, resulting in avoidable take-or-pay costs).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

overcome serious doubt or come forth with specific evidence showing that their actions were in fact prudent.

136. One would expect that specific evidence dispelling doubt and proving prudence in this case would include testimony of managers who made the allegedly imprudent decisions justifying why their actions should be deemed reasonable. Absent compelling reason for why these managers are unavailable to testify, their silence likely implies that they have no such specific evidence. Indeed, the "failure … to call as witnesses those officers who did have authority to act … and who were in a position to know … is itself persuasive that their testimony, if given, would have been unfavorable to appellants. The production of weak evidence when strong is available can lead only to the conclusion that the strong would have been adverse."[190] Here the Carriers did not make available Al Bolea President of BP Pipelines (Alaska) Inc., and offered no reason for his absence.

Affiliate considerations

137. Participants dispute whether the Carriers' affiliate relationships require heightened scrutiny. Staff contends that because the owners of TAPS are also the principal shippers on that system, the Carriers' efforts to prove that the SR Project was prudently undertaken deserve extra scrutiny. Staff IB 51. Anadarko agrees. Anadarko IB 30 (citing *Ne. Utils. Serv. Co*., 66 FERC ¶ 61,332, at P 62,089 (1994) ("The Commission long has recognized, and the courts have agreed, that transactions between affiliated companies require close scrutiny.") (citations omitted). Anadarko also asserts that because an affiliate relationship exists between the Carriers and their producers, prudence cannot be presumed. *Ind. & Mich. Mun. Distribs. Ass'n v. Ind. Mich. Power Co.*, 62 FERC ¶ 61,189, 62,238 (1993) ("If costs are incurred through a non-affiliate transaction, we presume prudence and typically assume an arm's-length relationship between the buyer and seller. In this circumstance, the complainants have the initial burden to come forward and present evidence casting serious doubt as to the prudence of the utility's conduct. If costs are incurred through an affiliate transaction, we cannot presume prudence or assume such an arm's-length relationship.").

138. Carriers point out that a heightened level of scrutiny does not apply in this case, because the heightened standard of scrutiny to which Anadarko and Staff refer has been applied only in situations involving transactions between affiliates, and there were no affiliate transactions in the SR project.

Discussion/Findings

139. While affiliate considerations in decision-making are a serious concern here, the cases cited by the Anadarko and Staff do not show that relationships between the Carriers and their affiliates necessitate heightened scrutiny of SR project transactions. As noted

[190] *Interstate Circuit, Inc. v. U.S.*, 306 U.S. 208, 226 (1939).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

by the Carriers, these cases concern transactions between affiliated entities.[191] The heightened form of scrutiny meant that the presumption of prudence is lifted when the expenses in question are incurred in an affiliate transaction.[192] In contrast to these cases, the SR project does not *per se* involve transactions between affiliated entities, and the burden of proof has already shifted to the Carriers, as determined in the Order on Burden of Proof.

140. Nevertheless, record evidence demonstrating that the Carriers considered benefits to their affiliates in their decision-making is relevant to prudence.[193] For prudent decision-making, only benefits to the ratepayers and not to shareholders or affiliates may be considered. *See, e.g.*, *Iroquois Gas Transmission Sys*., 87 FERC at 62,170 n.40 ("utility was denied recovery . . . because the company stood to derive significant financial reward from bringing a unit online quickly") (citation omitted); *Enbridge*, 100 FERC ¶ 61,260, at PP 337-340 (the applicant was not able to overcome serious doubt associated with costs attributable to several vendors who were associated with former KPC executives). As discussed below, the Carriers and affiliate producers did not have an arm's length relationship. As demonstrated below, business decisions by the Carriers were made with affiliate producer concerns in mind; therefore, the affiliate relationship must be taken into account when analyzing whether the Carriers' actions were prudent.

ii. Prudence Applied to this Case

1. Synopsis of Parties' Contentions

[191] *Northeast Utils. Serv. Co.*, 66 FERC ¶ 61,332, at P 62,089 (1994) ("The Commission long has recognized, and the courts have agreed, that transactions between affiliated companies require close scrutiny.") (citations omitted).

[192] *Indiana & Michigan Municipal Distributors Ass'n v. Indiana Michigan Municipal Power Agency*, 62 FERC ¶ 61,189, at 62,238 (1993) ("If costs are incurred through an affiliate transaction, we cannot presume prudence or assume such an arm's-length relationship.").

[193] *See, e.g.*, Anadarko IB 212 ("BPPA pushed to continue the SR project . . . [after] it had labeled the project as a "train wreck." BPPA did so to protect the 63 million barrels of reserves booked by its production affiliate, BPXA. BPPA believed that reserve booking would have been in jeopardy if the SR project was canceled."). Exs. AT 14-3; AT-13; SOA-11 at 17. No one denies the Carriers' affiliations, and certain entities are characterized as parents and affiliates by the Carriers themselves. Carrier IB 9 n.11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

141. The costs at issue are the portion of SR capital costs included in the Carriers 2009 and 2010 rates.[194] According to the Carriers these are determined by adding Alyeska's Carrier Property in Service (CPIS) for the years 2007-2009. *See* ATC-628.

142. The State argues that the cost estimates of the project were incorrect because the Carriers performed an inadequate preliminary engineering process, ignored the warnings of their own experts and the regulators, and proceeded to sanction with cost estimates that were not correct. In addition, the State asserts that the Carriers compounded the problem by mismanaging the execution of the project. Accordingly, the State avers that electrification was imprudent and its costs should be removed from rates. State RB 4. Specifically, the State argues that the Carriers did not scope or do sufficient front end loading (FEL) of the project before sanction and proceeded to the construction phase before sufficient engineering had been done. The State also argues that the SR team was inadequate and improperly managed. As a result, the project was over budget and over schedule. The State seeks disallowance of the imprudently spent SR costs in comparison to a prudently build hybrid project. Alternatively, the State avers that costs of execution were imprudently spent and should be disallowed.

143. Anadarko argues that an independent, prudent operator would have done the due diligence necessary to properly scope the SR Project in order to know the capital costs and operational savings associated with proceeding. In addition, an independent prudent operator would have contacted the regulatory and ratepayer stakeholders and explained the need for and the economics underlying the project. An independent, prudent operator would not have been subject to its affiliated master's agenda. Further, Anadarko contends that an independent, prudent operator would never have undertaken the SR project. Anadarko IB 14. Anadarko argues that if the costs or some of the costs are determined to be prudent, then a determination must be made as to (1) whether the prudently-incurred costs are used and useful to shippers, (2) whether the SR costs have resulted in a net and proportional benefit for shippers, (3) whether the SR costs are the result of a failed project, and (4) whether the SR costs are being borne by a generation of shippers that will benefit from the incurrence of those SR costs. Electrification, according to Anadarko served no useful service, the costs have left Anadarko worse off than before (neither major maintenance expenses or staffing levels have declined instead they are both rising). Anadarko IB 15. Since the project was solely economically justified (it would provide a net benefit to shippers by reducing operational expenses) it is clearly a failed project, since the benefits did not come to fruition. According to Anadarko, Owner misalignment also impacted the project. *Id.* at 38. Finally, Anadarko argues that since this is not a competitive market it must rely on rate regulation to protect it from the costs of imprudent behavior. *Id.* at 16.

[194] SR expenses are less than one percent of the Carriers' total cost of service for 2009 and 2010. Ex. ATC-35 at 8-9.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

144. The Carriers admit that the major mechanical equipment at the pump stations was being maintained in good operating order, although they claim it was inefficient and costly to operate at reduced throughput levels. Carriers IB 17. They also claim that the control systems, both system-wide and at the pump stations, were largely obsolete. *Id.* The Carriers also admit that SR was done to reduce costs (operating and maintenance expenses) [195] in an environment of declining pipeline volumes.[196] This was to be accomplished principally by de-staffing the operating pump stations and reducing personnel who supported the teams in the field. The Carriers claim they undertook an objective comparison of options, considered relevant and updated information, and gave appropriate weight to the costs, benefits and risks of proceeding as they did. The underlying analyses were developed by knowledgeable Alyeska personnel based on years of study, endorsed by the Alyeska executive team that recommended the project, and vetted by the Owners. According to the Carriers' the design was found to be consistent with industry practices, approved by Joint Pipeline Office (JPO) and welcomed by the State Attorney General.

145. The Carriers' further admit that once electrification was approved in early 2004, the project proceeded on a basis aimed at realizing the projected savings as rapidly as possible.[197] This was the largest TAPS project since original construction 30 years earlier. *Id.* The Carriers state that a leading independent consulting firm found the project to have been front-end loaded (planned and designed) to an above average degree. The project was led by a highly qualified team, state and federal regulators, through the JPO were consulted and informed at every step and prior JPO approval was obtained for important activities. The lead contractor was selected based on its reputation and successful performance on comparable projects and effective completion of preliminary engineering on SR. Other contractors were chosen following Alyeska's established procedures and standards.

146. However, the Carriers contend that labor and material shortages led to delays and escalating costs; significantly greater amount of work needed to be done in a "brownfield" environment than had been anticipated; and the lead contractor failed to deliver the leadership personnel and engineering staffing it had promised. Thus, the project cost more than originally anticipated and took longer to complete. The Carriers

[195] The Carriers also maintain that there were other matters such as aging equipment, changing crude characteristics, and increasing per-barrel costs. Carriers IB 16.

[196] TAPS throughput peaked in 1988 at 2.1 million barrels per day (bpd) by 1999 it had fallen to around half that level and continued on a downward trend. Ex. SOA-427 at 35-36.

[197] Carriers IB 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

contend that during 2005 they took cost containment measures: they put a hold on further project funding; undertook a reevaluation of the project and its management, and took significant remedial measures. The analysis revealed that even with cost growth and delay in realizing the anticipated savings, the project continued to show material net benefits that justified the additional funding. The Carriers also argue that if the project or portions thereof are deemed imprudent the remedy would be to eliminate $53.6 million about 10% of the costs.

2. From 1997-2000

147. Prior to SR, TAPS was a reliable system and had operated reliably in a remote location for nearly 30 years without significant modifications. Its reliability rate was 99.6 percent from 1977 through December 31, 2000. Ex. AT-165 at 4. TAPS was constructed with the capacity to operate unmanned. Ex. SOA-572 at 13 n. 22. However, after a fire at PS 8, there was full staffing at every station. Tr. 8025:15-18. The staffing was for safety, maintenance, and response capacity. Ex. SOA-572 at 13 n.22. Reliability was ensured by several redundancies. To wit, Aleyska added: field personnel to react quickly to unforeseen events, excess equipment (over $100 million in inventory of heavy equipment), multiple backup systems and a significant engineering organization. Ex. SOA-572 at 13.

148. The State and Anadarko proved that prior to electrification, Alyeska had studied various options starting as far back as 1994, including eliminating pumps, modifying pumps and other infrastructure changes (updating automation and system controls) to improve efficiencies. Options to change the original pumps with electrified pumps were considered and rejected. These studies were conducted with the purpose to provide economic positive benefits. After a number of studies it was concluded that it made economic sense to upgrade the control systems and automate equipment and that it did not make sense to change any of the pumps. With automation the work force could be significantly reduced.

149. However, in 2001, electrification was adopted in less than a year, conceptual engineering was done in less than a year, key Alyeska subject matter experts were ignored and the electrification studies lacked the analysis of the previous studies. The evidence in this case shows that starting in November 2001 the Carriers began considering solely electrification, and by December 2002, they decided to continue to preliminary studies on electrification. The rationale was to reduce staffing and operating costs.

150. The contrast between what was done prior to 2001 with what was done after is conclusive evidence of imprudent behavior. The actions undertaken in this time frame were not actions of a reasonable utility manager acting in good faith. Moreover, there were no studies invalidating the previous studies. If the Carriers had conducted reasonable engineering studies, or studies that conformed to industry standards, they

20140227-3052 FERC PDF (Unofficial) 02/27/2014

would have formulated reasonable costs and shown that electrification was not a viable option and thus would not have been sanctioned.

151. The Carriers claim that Alyeska led the project development. Carriers IB 18. This is not true based on the facts of this case as discussed below. They also assert that SR grew out of a systematic evaluation of alternatives and proceeded through the typical conceptual and preliminary engineering stages of project development. *Id.* This also is not true as established below. Next the Carriers argue that the Owners provided direction, technical support and funding and maintained close oversight throughout. The only part of that statement that is not supported by the record is that they provided close oversight.

Bailey Report Ex. ATC-102

152. The Bailey Report Ex. ATC-102 (also Ex. SOA-135) was conceptual engineering for control and telecommunications systems. The Bailey Report recommended alternative D which was for partial automation of the pump stations. This would have allowed remote control of the pump stations but 24-hour maintenance. Full automation or alternative F was not recommended because it was found to be uneconomic. The Bailey Report is analyzed below.

153. Exhibit No. ATC -102, entitled Control and Telecommunication Long Range Plan TAPS Instrument & Control System Conceptual Study Report May 1997, dated May 7, 1997, was produced by Alyeska Pipeline Service Company (APSC or Alyeska). This report is colloquially referred to as "The Bailey Report" as Terry Bailey was the project lead. Consistent with testimony in this proceeding, references to this document will be identified as the "Bailey Report."

154. Chapter 1 of the Bailey Report is an Executive Summary that consists of six (6) subsections. Section 1.1 is titled "Introduction" and identifies that the basis of the Bailey Report was a belief that automation upgrades to the pump stations to be implemented by the year 2000, could lower operating costs of TAPS. This section states that the Bailey Report is based upon a vision defined in the 1994 Controls and Telecommunication Long Range Plan. The 1994 Controls and Telecommunication Long Range Plan was not proffered by any party in this case and is not a part of this record. Ex. ATC-102 at 11-13.

155. Section 1.2 is titled "Recommendations" and concludes that economic analysis contained in the Bailey Report confirmed earlier beliefs that automation technologies could improve "operational efficiencies." This section cites to 1996 and 1997 Corporate Business plans (neither has been proffered by any party in this case and is not a part of this record) as suggesting that a multi-year investment would be required to implement the recommended upgrades to the TAPS control and instrument systems. The cost of this recommended project is estimated to be $53 million dollars by the end of year 2000. The Bailey Report recommends that Alternative "D" or the "Improved Operational

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Efficiencies" be selected for implementation. This recommended Alternative "D" is believed to return benefits of $20 million dollars per year. Additionally this section identifies an IRR of 44% and a post project payback of 2.8 years (as demonstrated in Table 3.2 in Exhibit No. ATC-102, on page 27 of 90).

156. Section 1.3 is titled "Proposed Scope of Work" and recommends four (4) systems to be considered as primary areas of improvement to obtain better operational efficiencies. These systems are identified as: Pump Station Instrument and Control Systems Upgrade, Pipeline Shutdown System, Pipeline Supervisory Control and Data Acquisition (SCADA) Replacement and, Valdez Marine Terminal (VMT) Recommendations. As the VMT issues are not germane to the instant case, as such, no further discussion will be made on this subject. *Id.* at 11.

157. For Pump Station Instrument and Control Systems Upgrades, the recommendation prescribes a "level of automation which retains 24 hour staffing of the pump stations, yet targets a significantly improved operational efficiency" replacing the control room equipment with state-of-the-art integrated control system which would be designed for "unattended control room operation and would provide maximum reliability, standardization and remote diagnostic capability." *Id.* at 11.

158. Additionally, the scope of work contemplated in the area of Pipeline Shutdown System would provide for the expansion of the Remote Gate Valve (RGV) project to include independent Pipeline Emergency Shutdown System (ESD). Finally, Pipeline SCADA replacement would link all pipeline instrumentation and control components in to a unified system in a standard Microsoft Windows environment throughout Alyeska, streamlining the duties of operational, administrative and support staff and maximizing efficiency. It is contemplated that a new pipeline control system operations console could be installed either at Fairbanks, Valdez, PS-1 or Anchorage. *Id.* at 12.

159. Section 1.4 is titled "Why Begin Now?" and describes this suggested Alternative "D" would take 3-4 years to complete and urges this program be initiated in 1997 to capture $20 million dollars in yearly benefits as cost savings and suggests that each month delayed would result in a loss of $1.66 million dollars, monthly. Additionally, further cost implications are noted involving commitments made to the Joint Pipeline Office (JPO) regarding the Operations Control Center (OCC) physical facilities which would need to be rescinded if this initiative is not funded. The exact nature of what past commitments Alyeska made to JPO, with respect to the "OCC physical facilities," is not discussed in The Bailey Report. Ex. ATC-102 at 12.

160. Section 1.5 is titled "Impact on Operations" and recognizes that this project is a multi-year venture requiring 3-4 years to implement through completion and that a Preliminary Engineering phase should last 9-12 months with the first changes to pipeline operations occurring approximately in 12-15 months. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

161. Section 1.6 is titled "Impact on Budget" and states that the control systems upgrade was included in the 1996 and 1997 Corporate Business Plans as part of the strategy of investment in technology. *Id.*

162. Chapter 2 is titled "Overview" and is an examination of past initiatives and studies upon which the Bailey Report is based. Section 2.1 (History) and Section 2.2 (Vision Derived from 1994 Study) is an examination of past plans and proposed changes principally to Alyeska's control and telecommunication systems.[198] The report states that it focused on involving Operations in the team and decision process. Operations reviewed and refined the scope as well as agreed with the benefit estimates. "As a result we can deliver a recommendation that is endorsed by Operations." *Id.* at 16.

163. Section 2.3 (Development of Alternatives) describes prior studies and plans as lacking sufficient scope definition to produce estimates of costs and benefits and identifies the goal of the Bailey Report "to provide more detailed alternatives so that an economic evaluation of these alternatives could be performed." Ex. ATC-102 at 15. It is in Section 2.3 where Alyeska develops three operational models as the focus of the Bailey Report. Described as "the most radical proposal," full automation of the TAPS Pipeline is outlined here for the first time (*see* Section 2.3.2 titled "Facility Optimization"). Full automation envisions an operation mode where no personnel are dedicated to any facility, where all process restart activities would be automated, where a limited number of "rovers" would be available to assist in emergencies and, most manual observations and control functions would be automated. A second operational model considered is one where: each facility (pump station, VMT, others) has a day time staff but no night time dedicated staff and, requires sufficient system modifications for the facilities to be monitored at night from an off-site control room. It is noted that this second mode of operation requires less automation of restart processes and less instrumentation as compared to the full automation mode described above. Lastly, a third mode of operation is considered that would retain 24-hour staffing of facilities, but at a reduction from current (1997) staffing levels. This third mode of operations would be

[198] Specific upgrades at the pump stations identified in the 1994 LRP were: a small supervisory control and data acquisition (Mini-SCADA) system, Programmable logic controllers (PLC), high speed process control data highways using IEEE 802.3 Ethernet network standards, and replacement of the alarm and relay logic control panel (SCP) with PLC technology. *Id.* at 16. *See* Tr. 7840-41 (Pomeroy). The Bailey Report summarizes other undertakings: in 1995 Alyeska developed a company standard for PLCs and single loop controllers and acquired budgetary proposals for control systems upgrades. In 1996, conducted detailed research to determine possible tangible and intangible benefits from the project and initiated the conceptual engineering phase to develop alternative scope/cost/benefit scenarios for review and evaluation with Operations organizations which finalized in the Bailey Report. Ex. ATC-102 at 15. As can be seen conceptual engineering for the Bailey Report lasted a year.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

achieved through the elimination of "routine tasks and the instrumentation of precursor signals known to be indicative of impending incidents." *Id.* at 17.

164. Section 2.3.3 is titled "Instrumentation Technology" and discusses how technology may be applied to "reduce manual activities, improve safety, or reduce maintenance problems" (Ex. ATC-102 at 18). It is noted that the logical connector 'or' is used in this sentence. This may imply that reducing maintenance problems may be mutually exclusive to the goals of reducing manual activities and improving safety. *Id.* at 18.

165. Section 2.4 is titled "Evaluation Methodology" and describes three (3) conditions that must be met in evaluating the above stated alternatives as: technical accuracy, commercially convincing and, feasible for Alyeska organization to implement. Financial indicators examined to assure the strategy chosen would be "commercially convincing" are listed as: Internal Rate of Return (IRR), Net Present Value (NPV), Payback Period, and Cost Reduction Index (CRI). *Id.* at 19.

166. Section 2.5 is titled "Organization of Documents" and identifies the organization of the Bailey Report into two TAPS operational areas: Pipeline and VMT. A clear statement is also made with respect to Supporting Volumes (Volume 1 and Volume 2) containing technical information describing the "scope of work" and backup materials describing the "calculation of program benefits." *Id.* at 20. The Appendices were not made part of this record until the supplemental hearing in Phase I.

167. Chapter 3, titled "Pipeline Analysis," is the crux of the Bailey Report as this section describes six alternatives that were studied and highlights a recommended choice for implementation. Each alternative, A through F is discussed in Section 3.1 in increasing order of complexity of implementation. Each alternative discussed cost and benefits of each strategy. Section 3.1.1, titled "Business as Usual," is termed the "do nothing case" and is referred to as Alternative A. This "do nothing case" is the base case for "business as usual." It is noted in this section that costs for this strategy were "hard to develop" given that Alyeska has operated with a "lack of central implementation which has led to diversity within instrumentation and control systems." Simply stated, up to this point in 1997 it seems that Alyeska had implemented pipeline systems *ad hoc*, as necessary, without an emphasis on system wide continuity and pipeline system standardization. This base case (or do nothing case) is estimated to cost $16 million dollars with little change in functionality for TAPS. *Id.* at 22.

168. Alternative B is discussed in Section 3.1.2; it is titled "Fuel and DRA Optimization." Alternative B considers optimizing the use of a Drag Reducing Agent (DRA) and optimizing fuel usage in the Rolls Royce Avon gas generator turbines (Avon

20140227-3052 FERC PDF (Unofficial) 02/27/2014

turbines)[199] trough an "expert algorithm" monitoring and adjusting real time operating conditions of the Avon turbines and DRA injections to achieve optimum operating points. The estimated cost of this alternative is $10 million, with an associated benefit of $17 million. *Id.*

169. Alternative C is discussed in Section 3.1.3; it is titled "Control Room Equipment Replacement." Alternative C starts with the suggested changes of Alternative B and adds two (2) projects to the Alternative B scope. These two projects consist of; 1) renewed pump station control room which would add a new operator console that would communicate with all smart devices in the pump station and, 2) replacing the existing pipeline portion of the OCC SCADA with a new SCADA system. *Id.* at 22-23.

170. Alternative D is discussed in Section 3.1.4; it is titled "Improved Operational Efficiency." Alternative D starts with the cumulative implementation of Alternatives A through C while adding to the scope: Replace the Unit Control Panel (UCP), and Station Control Panel (SCP) equipment in the pump station control rooms, and Major addition of instrumentation in the station. A stated goal of this Alternative is to be able to "run the pump station with no 'operators' or 'rovers.'" It is stated that this Alternative would "allow operational control of the pump station to be assigned to neighboring stations, or to OCC." Additionally, it is noted, "new turbine instrumentation and controls would permit OCC to safely start the main line pumps (MLUs), and adjust the speed of individual MLUs to avoid operating in critical speed or high vibration." The task of the maintenance personnel would be reduced so that they could take on tasks formally assigned to the control room operator not related to instrumentation or control. *Id.* at 23.

171. Alternative E is discussed in Section 3.1.5; it is titled "Day-time Staffing." This option is described as an alternative to further expand the SCADA upgrade as discussed in Alternative D. Alternative E would embrace the scope of work required to safely operate the pump station with no one assigned to night duties. Ex. SOA-729 gives more background into the type of work required for Alternatives E and F. *Id.*

172. Alternative F is discussed in Section 3.1.6; it is titled "Fully Automated Pump Stations." This section contemplates "design as a new pipeline using 1997 principles and technology" operating each pump station in a manner similar to "unattended facilities similar to modern off-shore oil production facilities." The unique feature of Alternative F is the fact that, "There would be periods of time when no personnel (operation or maintenance) are at the location." A noted comparison is made to Alternative E which is

[199] The Avon turbines are not mentioned explicitly by name in the report, but it is clear this is what is being discussed. The report discusses at this point "Fuel" usage, it is fuel that runs the Avon turbines that drives the pumps so while the Avon turbines are not mentioned explicitly, it is clearly implicit the Avon turbines are the referenced machines with the use of the word "fuel."

20140227-3052 FERC PDF (Unofficial) 02/27/2014

instructive: "Alternative E replaces the 'eyes and ears' of the pump station operators with instrumentation. Alternative F goes farther and adds the automated valves to replace the 'hands' of the operator." Additionally it is noted that a reduction of maintenance staff of 50 percent could be achieved under Alternative F. Alternative F[200] is described as having significant additional scope. This additional scope is listed as: revised instrumentation and control of heating and ventilation systems (HVAC), replacement of fire and gas system and fire panel, replacement of manual valves with actuated valves, additional cameras for OCC and security usage, additional turbine fuel measurement and tank level gauging and, significant increase in number of instruments required.[201] *Id.* at 24.

173. Section 3.2, titled "Cost Estimates," specifies the process employed to develop the cost estimates used to compare Alternatives D, E, and F. Alyeska did not to pursue cost estimates for Alternatives A, B and C. *Id.* Section 3.2.1, titled "Estimation Process" indicates that Pump Station (PS) 9 was selected as a "typical" pump station and this pump station was used for a description of the pipeline scope of work. Estimates for other stations were based upon scaling factors which were derived from the number of instruments and the number of instrumentation drawings that exist for each pump station.[202] Ex. ATC-102 at 25 (listing scaling values for each pump station in Table 3.1); Appendix F.1 at 25. From review meetings with operational representatives, it was determined that program success would be linked to the elimination of some existing defects. As an example, it states that some of the motor control centers would need to be fixed to assure reliable operation of start and stop commands. Each alternative would have different requirements for defect elimination; greater control scope of work, the greater number of defects that would be needed to be fixed to assure that the benefits would be achievable. The overall program estimate included the estimates to perform the basic defect elimination. *Id.*

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[200] Of all the proposed Alternatives in the Bailey Report, including all scoping activities and modes of TAPS operations, Alternative F is closest to the proposed "Hybrid" Proposal submitted and described in ATC-154, "Electrification vs. Hybrid Decision Document, October 28, 2002.

[201] Note that for non-MLU turbine control system upgrades there is an ID No. 143 under Alternative F which states "consider replacing Garrett turbines with Solar. One Solar could replace two Garretts with significantly lower maintenance cost. This item was dropped from consideration." *See* SOA-729 at 23.

[202] This section describes, "[t]he base estimates for materials and labor have been factored to include indirects and overheads following standard Alyeska project estimating rules," thus Alyeska attempted an honest estimation including indirect costs to achieve a high level of confidence in their estimation process. Appendix G. *Id.* at 25.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

174. Section 3.2.2, titled "Estimation Results" shows the cost estimates for Alternatives D, E and F are $52.6, $94.8, $126.5, million dollars, respectively. To verify the cost estimation process, a Monte Carlo simulation was done that indicated a 90% certainty level of achieving project completion at the estimated costs. These estimated costs were based on a fixed scope of work. *Id.* It is understood that this means that no other projects (or work) would be performed on the pipeline system beyond what was planned to implement the chosen alternative.

175. Section 3.3, titled "Benefit Estimates" enumerates several advantages of automation and classifies these benefits as both tangible and intangible and characterizes automation as having the ability to "affect the allocation of staff to assignments, allowing greater efficiency of operation." This section also notes that, "[a]utomation does not directly determine staffing levels. Rather, automation gives management a greater set of options to achieve staffing goals of the Corporate Long Range Plan." *Id.*

176. Section 3.3.1, titled "Estimation Process" and is self-explanatory. Of note in this section is the fact that the time horizon utilized for the economic analysis is a ten year evaluation horizon along with an 11% discount rate factor to calculate a present value (PV) of the benefit "stream" of automation. The most significant savings, 54%, is achieved through "directly affected pipeline staff" with an additional 14% of savings achieved from "Urban Staff." *Id.* This implies that vast majority of program savings (70%) will come from full time employment staff reductions. Exhibit SOA-737 attributes the 54% to pipeline staff reductions, urban direct reductions of 7%, urban indirect reductions of 9% to option D. (Ex. SOA-737 at 11). *Id.* at 26.

177. Section 3.3.2, titled "Estimation Results" identifies the benefit estimates for alternatives D, E and F as $88, $99 and, $110 million dollars, respectively. *Id.*

178. Section 3.4 is titled, "Comparison of alternatives" lists three tables (Tables 3.2, 3.3 and 3.4) for comparison purposes with the alternatives grouped by financial considerations, operational concept and magnitude of the scope of work. The recommended alternative is Alternative D, Improved Operations. Additionally, Table 3.5 (Ex. ATC-102 at 31) presented in this section is a risk analysis of each alternative. Table 3.5 shows that Alternative D has significantly less risks than Alternatives E or F. *Id.* at 26-27.

179. Section 3.5, titled "Economic Evaluation" describes the primary criteria used to develop the recommendations in the Bailey Report. The criteria are "return on investment with manageable risks." A secondary consideration is listed as "operations and maintenance philosophy for Alyeska to achieve corporate goals." Several tables are presented comparing cost benefit ratios, NPV, and IRR of Alternatives D, E, and F. Alternative D consistently shows the "better financial indicators when compared to other alternatives." *Id.* at 31 and 35.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

180. Section 3.6, titled "Recommended Scope of Work" is broken down into three sub-sections (Section 3.6.1 titled, "Overview,"[203] Section 3.6.2, titled "List of Systems," [204] and Section 3.6.3 titled, "System Details"). The descriptions in this section identify the scope of the work undertaken to accomplish reasonable cost estimates of each identified alternatives. The scope of work described in this section appears to be complete and comprehensive with details appropriate for a Conceptual Engineering phase of project study. The scope of work described what was to be performed at all pump stations, including ramp-down stations and modifications to the OCC, provide for a +/- 40% cost estimation of Alternatives "D", "E" and "F." [205] *Id.* at 37.

181. Section 3.7, titled "Comparison to 1994 LPR Recommendations," cites to Appendix D to illustrate the changes in scope between the 1994 recommendations and

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[203] The following modifications at the stations were listed, replacement of: existing Sq. D communications PLC with a SCADA systems and human-machine interfaces (HMIs); the station control panel (SCP) controls with a PLC; the mainline pump control panel controls (UCP's) with a PLC; the Solar and Garret panels; the fire and gas panels. In addition: installation of a utility systems PLC; refrigeration/brine system control upgrade; DRA automation; fuel optimization and upgrade of approximately 80 miscellaneous end devices. *Id*. at 37. At the OCC it specified replacement of the pipeline functionality of the MV20000 with new PC-based computers and peripherals. *Id.*

[204] The Bailey Report describes 24 systems which were used for cost estimation purposes: Miscellaneous Instrumentation Upgrade; Enterprise SCADA and Control Room Infrastructure; Station Control Panel Upgrade; Unit Control Panel Upgrade; Fire & Gas System Upgrade; Non-MLU Turbine Control Systems Upgrade; Ramp-Down Station Upgrade; Hydraulic Skid Automation; Air Intake De-Icing System; Plant Y Instrumentation Air System Upgrade; UPS for Critical Applications; Utilities Systems Automation & Upgrades; Emissions Monitoring Automation; Electrical System Upgrade; Power Generation System Upgrade; HVAC & Therminol Systems Upgrade; DRA System Optimization; Fuel Gas Compressor Automation; Security & Surveillance Systems Upgrade; Process Equipment Upgrade; Fuel Loading Automation; Metering System Upgrade; Refrigeration/Brine Systems; Fuel Forwarding Skid Automation. *Id.* at 39. The Non-MLU turbine control system upgrade included replacing the existing Solar & Garrett turbine control systems with a "vendor designed & fabricated package system," installation of vibration monitoring equipment, elimination of all manual data logging with dedicated transmitters tied to PLC and upgraded or replaced all marginal process and mechanical equipment and hardware (fuel valves, actuators, governors), and upgrading the fuel control system (fuel valve, actuator, governor). *Id.* at 44.

[205] The pump stations involved in Bailey are PSs 1,3,4,5,7,9 and 12. Ex. SOA-729 at 23. The ramp-down stations are PSs 2, 6, 8, and 10. *Id*. at 25.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the recommendations contained in the Bailey Report. It is noted that the major changes between 1994 and 1997 reports was a significant increase in the amount of field instrumentation and a significant amount of work to eliminate perceived defects of the 1994 study. *Id.* at 49. Ex. SOA-733 is Appendix D.

182. Section 3.8, titled "Costs of Recommended Alternatives" contains a cost estimate summary worksheet (Figure 3.7, Ex. ATC-102 at 50) showing the accounting for indirect and overhead expenses that were used in the estimation process. Also included in this section is a "Crystal Ball" simulation (Figure 3.8, Ex. ATC-102 at 51) used to model Option D in order to quantify the uncertainties in the cost estimate. Ex. ATC-102 at 49.

183. Section 3.9, titled "Schedule for Recommended Alternative" identifies Alternative D as a "major multi-year undertaking" while opining an "assumption that only one pump station would be at risk of unplanned shutdown at any time." Of note in this section is the fact that a preliminary schedule was developed. In this schedule, Conceptual Engineering took less than one half a year (1-1-97 to 5-30-97). Preliminary Engineering is scheduled to last approximately, a bit more than one year (6-2-97 to 9-7-98). Work on pump station upgrades was scheduled utilizing a (mostly) parallel work schedule with a total of six (6) pump stations being upgraded simultaneously in the third quarter of 1999. At all times of the proposed construction schedule, no fewer than two (2) pump stations were scheduled to be worked upon at any one time (*see* Figure 3.9, Exhibit ATC-102 at 52).

184. Chapter 4 contains the recommendations of this conceptual study with respect to what upgrades to the VMT should be considered. Other than the fact that the VMT is not at issue in this instant case, one interesting comment is noteworthy in this section. The Bailey Report finds that no work at the VMT should be done due to the lack of a compelling business case. *Id.* at 54.

185. Chapter 5 of the Bailey Report is titled "Recommendations for Preliminary Engineering," and is further broken down into two subsections discussed below. In the introductory paragraph of this section it is shown that Alternative D is estimated to save $20 million dollars per year. This represents a per barrel reduction in transportation costs of $0.05 in the year 2000, assuming 1.2 million barrels of oil per day throughput. *Id.* at 69.

186. Section 5.1 is titled "Scope of Work for Preliminary Engineering" and reports that this conceptual engineering report (the Bailey Report) includes a rough order of magnitude cost estimate of +/- 40%. It is also stated that, "[t]o arrive at a +/- 25% cost estimate in support of a fully funded AFE requires detailed scope analysis to minimize project risks and adverse consequences." Three (3) major tasks during preliminary engineering are identified as necessary to achieve a refined +/- 25% cost estimate: Definitive Scope Development, Project Implementation Planning and, AFE Preparation.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

It is also stated that once preliminary engineering is completed and a full funded AFE is approved, the project will progress into the detailed design and implementation phases.

187. Section 5.1.1 is titled "Definitive Scope Development" and identifies many tasks that must be conducted to further refine the scope of work discussed in the Bailey Report. An observation here is the validation of certain assumptions made in The Bailey Report which must be verified in the preliminary engineering phase. An outcome of "this task" (preliminary engineering) is a design freeze or scope freeze which locks in the scope of work to be estimated for the full funding request and, "All scope changes (adds, deletes, and modifications) after preliminary engineering are to be trended back to the baseline scope." Importantly, it is recognized that the output of the preliminary engineering phase would comprise an Issued for Design scope package that will be treated as "the design "freeze."" Also identified in this section are twenty-one (21) studies that will be conducted during preliminary engineering. It is noted that each of these studies could have a significant impact on arriving at a control estimate accuracy of +/-25%. The studies that are to be completed during preliminary engineering are listed as: Codes and Regulations Study, Communications Interface Study, Control Center Study, Data Modeling Study, Design Basis and Guideline Study, ESD and Redundancy Study, Existing Utilities Study, Fire & Gas Protection Study, Facility Operability and Risk Assessment Study, Heat Trace Study, Operations Logistics Study, Software/Database Platform Study, Technology Platform Study, Expanded Scope Study, Field Validation Study (as-found condition), Specifications, Control Sequences and Strategies, Tag Listing, Operations Requirement Document, Drawing Templates, and, Functional Requirement Document. *Id.* at 69-70.

188. Section 5.1.2 is titled "Program Implementation Program" lists projects that are similar, but not identical, to the Definitive Design Development tasks listed in Section 5.5.1. Some tasks in the Program Implementation Program overlap with the Definitive Scope Development but were to be coordinated as appropriate. The Program Implementation is meant to identify how the project will be executed in the Detailed Design, Installation and Start-up phases later after preliminary engineering was completed. Thirteen (13) studies and plans are identified in this section, including: Construction Logistics/Permitting Study, Contracting & Procurement Strategy Study, Project Execution Strategy Study, Project Quality Study, Contract & Procurement Plan, Project Execution & Staffing Plan, Construction Plan, Project Controls Plan, Risk Assessment Plan, Project Quality & Inspection Plan, Document Management Plan, Budget Planning and, Training Plan. *Id.* at 73.

189. Section 5.1.3 is titled, "AFE Preparation" and states that the major deliverable from the Preliminary Engineering phase is a full-funded AFE for the upgrade project. It is clearly stated that the Alyeska AFE Control Manual will be the guiding document for this activity. This section also states that this project will involve both capital and expense components and will be funded over multiple years, with a parenthetical

20140227-3052 FERC PDF (Unofficial) 02/27/2014

statement indicating the belief that the project will require more than 3 years to complete. *Id.* at 74.

190. Section 5.2 is titled "Preliminary Engineering Staff / Cost Estimate" and introduces Table 5.1 which outlines the cost centers (staffing hours and staff positions along with a 13 month planning horizon) to estimate the investment needed to perform the Preliminary Engineering for the Control and Telecommunication upgrades discussed in The Bailey Report. The estimated total cost for Preliminary Engineering is $2,278,000 (in 1997 dollars). Ex. ATC-102 at 76. *Id.* at 75.

191. Section 5.3 is titled "Schedule of Preliminary Engineering" and presents Figure 5.1 containing estimated start and finish dates for each study and plan discussed above to complete Preliminary Engineering. *Id.* at 77.

192. Chapter 6 is titled Program Implementation Considerations and contains four (4) subsections: 6.1 titled "Recommendations," 6.2 titled "Resource Requirement" and, 6.3 titled "Cost Summary" and, 6.4 titled "Program Phasing." Section 6.1 includes recommendations for: Program Approach, Program Management, Program Staff Organization, Buy or Build, Operational Impact. *Id.* at 79. In Section 6.1, the Report states that implementation would not require any planned pipeline shutdowns. *Id*. at 79. Low- risk tasks could be undertaken first. Work requiring shutdown could be coordinated with pipeline planners and cutover work could be done in such a manner as to ensure minimum pipeline shutdowns. *Id.*

193. Section 6.2 is titled "Resource Requirement" and provides a breakdown of what resources will be needed to complete these projects listed in this report. It is stated that 30% of total project scope is in engineering disciplines, 30% in purchased materials, 35% in installation and 5% management. *Id.* at 80.

194. Section 6.3 is titled "Cost Summary" and reports the cost estimate and spend plan of the recommended program. *Id.*

195. Section 6.4 is titled "Program Phasing." It is noted in this section that in order to achieve the projected benefits of The Bailey Report the program must be implemented in a timely fashion and that any delay in benefits affects the calculation of net present value as well as the internal payback period. Upgrade of pump station control systems by 1999 and SCADA replacement in 2000. It describes how the program could be implemented by a pilot project, all the work would be performed on a single pump station first. Alternatively, a work package for a subsystem could be developed and all work at all pump stations could be done at the same time before initiating changes to other subsystems. *Id.* at 81.

196. Chapter 7 provides a Glossary of Terms utilized in the Bailey Report. *Id.* at 83.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

197. Thus, as can be seen above, the Bailey Report was a conceptual engineering study for automation which recommended changes to the control function while requiring maintenance personnel presence at the stations rejecting the totally unmanned station alternative. The project would take three to four years to implement performed in such a manner that disruptions to operations would be minimal. It also projected $20 million in savings per year from implementation of Alternative D.[206]

Reinvestment Strategy- Draft Report January 18, 1999

198. Exhibit ATC-105 is an email form C. C. Fuzzard to W. G. Tonkins dated January 18, 1999, with the subject line of, "Reinvestment Strategy." This email has two (2) attachments, both Microsoft Word files titled, ReinvReportb.doc (96kb) and, ReinvES ALTERMATE.doc (18k). The email states that this is the latest version of the Reinvestment Strategy and it is "just the text of the report," (no tables or graphs in this copy). Additionally, the email identifies the second file as an Alternate version of the Executive Summary. The attached Word files are designated as Draft. Pages 2 through 18, of ATC-105, are marked "DRAFT." Pages 19 to 21 are blank and 21 does not have the draft designation, but in context it is assumed that this page is a draft also.

199. This report (Ex. ATC-105) is a draft and is not supported by any engineering, financial or, empirical data whatsoever. In spite of the lack of supporting documentation in this exhibit, it does hold some evidentiary value. A review of the contents of this exhibit is helpful in understanding the genesis of the project that has come to be known as Electrification and/or Strategic Reconfiguration (SR). This exhibit shows what the Carriers knew at this point in time, including the fact that electrifying a limited number of pump stations was considered and rejected. A similar report appears at Ex. SOA-143 but this exhibit does not contain the alternate executive summary.

200. The Draft Report of Exhibit ATC-105 contains six (6) chapters with sub-sections. There are two Chapters titled "Executive Summary," one on page 2 of ATC-105 and page 21. The difference in the Executive Summaries invites comparisons as they are divergent in significant regards. The first Executive Summary on page 2 of ATC-105 has two (2) subsections: 1.0 titled, "Executive Summary" and, 1.1 titled "Recommendations." Section 1.0 on page 2 of ATC-105 states that this study focuses on technical and economic facility changes for the purpose of improving efficiencies for TAPS. It is stated that the level of alternative evaluation used in this study is suitable for screening opportunities with "Robust Economics." Also noted is the fact that any investments that have marginal economic benefits would require further engineering and analysis of benefits in order to proceed.

[206] The Bailey Report is also summarized by the State in its IB pages 268-280. Exhibits SOA-729-739 are appendixes to the Bailey Report.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

201. In Section 1.1, titled "Recommendations" (Ex. ATC-105 at 2) the primary recommendation of this Draft Report is to improve the current "base case" using the Avon turbines. It recommends new impellers at pump stations 1, 3 and 4 to avoid critical speed problems, ongoing sensitivity studies for operational tradeoff between fuel and Drag Reducing Agents (DRA) as fuel prices vary and a comparison of competing DRA products. The recommendations section also noted that there may be other reasons for capital investment other than economics, but such reasons were not evaluated in the study. Ultimately it is recommended that the next step should be the follow-up of any alternatives with more detailed engineering analysis to "flesh out the costs and detailed economics."

202. Chapter 2 is titled "Overview" and has three (3) sub-sections. Section 2.1 is titled "Introduction" and identifies the team members while specifying that this report is an engineering study of pipeline facilities. Section 2.2 is titled "Purpose" and states that this study is to, "further the commitment from the 1999 Operating and Long Range Plan (1999-2008): Alyeska will identify reinvestment opportunities to address maturing systems and to further future efficiency gains. Alyeska will be performing life cycle analysis and developing a maintenance long range plan that identifies areas to target for reinvestment." Section 2.3 is titled "Scope" and states that the study is focused on "possible facility changes where investment would further efficiency gains. The focus was on technical feasibility and foreseeable economic benefits." Emphasis of this study scope is identified as concentration on the "pumping oil' function. Ex. ATC-105 at 3.

203. Chapter 3 is titled "Analysis" and is subdivided into several sections and subsections. For purposes of simplification, a synopsis of this chapter is offered. All attempts have been made to condense this material into an understandable summarization while maintain the integrity of the information contained therein.

204. The General Approach or Section 3.1 states that it uses Value Engineering Principles from PM 2001, Appendix 4, Section 8.2, a document not in this record. The requirement of this study is listed as, "What is needed in this case is a system capable of 1.7 to 0.8 MMBPD (million barrels per day), using four people total at each operating Pump Station. This study began with no limits on scope but the focus narrowed largely to "pumping oil function economics." Ex. ATC-105 at 4. It is noted that "80% of the 1999 budget is not directly attributable to pumping oil" and this study focuses on the key function where "currently 20% or less of the costs resides." Ex. ATC-105 at 5.

205. Four alternatives were considered for pipeline investment, some listed with options. The Base Case was Do Nothing except Necessary Lifecycle Replacement/Rebuild, with three (3) sub cases. Alternative 1 was to Replace the Avon/Cooper Drivers With More Modern, More Efficient Drivers And Automatic Controls At PS 7, 9, & 12. Alternative 2 is listed as, Upgrade the Existing Avon/Cooper Set With New Cooper RT 56 Two Stage Turbine, Gear Box, Automatic Controls. Alternative 3 was One Super Pump at Pump Station 9. Finally, Alternative 4 was listed

20140227-3052 FERC PDF (Unofficial) 02/27/2014

as, Electrical Drivers at PS 7 And 9 with four (4) sub-options. Each Alternative, with any sub-options listed, is discussed below. Ex. ATC-105 at 5-10.

206. The Base Case, Do Nothing except Necessary Lifecycle Replacement/Rebuild, contemplates maintaining the legacy Avon 1533 gas generators along with the Cooper RT 66 single stage turbines with a contractor performing maintenance for at least 20 years. A noted exception is that the turbines will probably reach an end of life caused by thermal creep which will be indicated and determined by monitoring. Noted also is that for purposes of the *economics of this study* (emphasis added) a very conservative assumption was made that the "turbine component will be replaced for all drivers in 5 years at a cost of one million dollars each" (in 1999 dollars). *See* Ex. ATC-105 at 5. A suggestion was made to reconsider using RT 56 when turbines are replaced. Sub cases explored for the Base Case are: 1) restarting topping units to reduce the cost of fuel, 2) considering installing pumps at PS 5 ($25 million for installation of pump), and 3) more DRA injections at optimal sites with remote control. Ex. ATC-105 at 5-6.

207. Alternative 1, Replace the Avon/Cooper Drivers with More Modern, More Efficient Drivers and Automatic Controls at PS 7, 9, & 12, estimates the purchase costs for new replacement drivers at $4 million. It was also assumed that $4 million was needed for modifications to existing building to accommodate the new drivers and, $2 million was added for automation upgrades. The total estimated cost is $10 million for new drivers and controls. Several specific machines were suggested to replace the Avon units while no specific suggestion on which manufacturer/machine combination to implement this alternative. The reason stated for not identifying a preferred manufacturer/machine combination was that the intention of this economic study was to discuss a combination that was available for purchase, but not drive the decision on what manufacturer/machine to select prior to proper engineering studies being undertaken.

208. The practicality of Alternative 1 is demonstrated quite cogently in this draft report. A passage from Ex. ATC-105 illustrates what was understood, in 1999, about the current configuration of the Alyeska Pipeline MLUs. It is reproduced here to illustrate what was known in 1999 about the operational status and fit for purpose conditions of the Avon/Cooper RT MLUs.

> If Alyeska were to replace the drivers with more efficient units, it would likely involve a high speed multi-stage power turbine instead of the direct drive single stage turbine we now use with the Avons. The current turbine arrangement is inherently inefficient, but it is simple, reliable and flexible (can operate within a larger range of horse-powers) and was selected originally for that reason. The more efficient units would fit in the same space as the Avons, but need to drive the pump through a gear box to allow the turbine to run at a higher speed. The gear box is inherently more complicated and may reduce reliability and increase maintenance

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> effort. It was noted in discussions during the study, that gear boxes have been improved in reliability and proved in service since the pumps were originally installed and that installing a higher speed turbine with the reduction gear box is a practical alternative.
> The hydraulic runs made during the study indicated that the existing pumps will generally be running at over 80% efficiency under the throughputs anticipated. It is not considered necessary for economic purposes to replace the existing pumps to improve efficiency.

Ex. ATC-105 at 6-7.

209. Alternative 2, Upgrade the Existing Avon/Cooper Set With New Cooper RT 56 Two Stage Turbine, Gear Box, Automatic Controls contemplates upgrading the Cooper Reaction Turbines with more modern equivalents that would require fewer physical plant modifications than Alternative 1 (Avon Replacement). A noted disadvantage is that a speed reducing gear box must be added which would introduce an element of risk to the reliability of the pipeline system. It is estimated that the cost of implementing this alternative would be in the order of $6 million per unit. Ex. ATC-105 at 7.

210. Alternative 3, One Super Pump at Pump Station 9 considers placing one "super pump" at PS 9 which would offer greater fuel efficiency while allowing some of the existing Avon units to remain at PS 9 for back-up and reliability purposes. It is noted that this option is only viable for throughputs less than 1.2 million barrels of oil per day. Installation of an additional super pump was considered for PS 1 (because PS1 is the only other station that could use a higher horse power unit) but this was rejected due to financial considerations. The unit for the super pump is contemplated to be a GE LM 2500, selected for its efficiency, durability and proven operations. The total installed cost of Alternative 3 is estimated to be about $19 million. Ex. ATC-105 at 7-8.

211. Alternative 4, Electrical Drivers at PS 7 and 9 contains four (4) sub-options, each of which will be addressed below. The common thread throughout Alternative 4 is that power to operate any new electric pumps would be purchased from a third party supplier. Specifically mentioned is Golden Valley Electric Association (GVEA) as a third party power supplier. It is stated that GVEA would provide 138kV power, power lines, and transformers to the required on-site voltage level needed as well as any voltage control equipment such as energy storage or a static VAR compensation system. Cost of the infrastructure needed would be recovered in the long term power contract. GVEA quoted (as preliminary) an interruptible contract utilizing a take or pay concept on a ten year term at about $0.051/kW-hr at PS7 and $0.49/kW-hr at PS 9. PS 9 would utilize two electric pumping systems while PS7 would use one. It is estimated that each electric pumping system would cost $1,995,000 (in 1999 US dollars). Additional costs would be incurred for removing the old AVON units and installation of needed electric motor auxiliary equipment at an estimated cost of $8 million installed. It is noted that a possible

20140227-3052 FERC PDF (Unofficial) 02/27/2014

additional expense may be incurred at PS 9 due to the necessity of starting two large electric motors simultaneously which may require a slightly different configuration to accommodate such a large electric load. Ex. ATC-105 at 8-9.

212. Four options are presented for Alternative 4. These are: Alternative 4.A, Co-Generation At PS 9 And Wheel Power To PS 7 To Power Electric Motors; Alternative 4.B, Use Alternative Power, Such As Electrical Line From Dead Horse, For Northern Stations; Alternative 4.C, Run PS 12 Off The Terminal Power Plant, and, Alternative 4.D, Power Recovery Turbine (PRT) At MP 238 (Somewhere South Of Atigun) for Power At PS 4. Ex. ATC-105 at 8-10.

213. Alternative 4.A references a study by Hobbs Industries; this report is not part of this record. The purpose of this sub-option (Alternative 4.A) is to assess the feasibility of installing co-generation facilities at PS 12 to provide power to the proposed new electric motors and pumps at PS 12 and simultaneously provide power to the Cooper Valley Electric Association (or CVEA) grid near PS 12. It is noted that eight full time employees would be used to operate the co-generation plant and contractors would be used for maintenance. The estimated cost of this co-generation plant at PS 12 is $15,800,000. Also contemplated in this sub-option is the provision of electric power to PS 9. It is stated that such a system was not evaluated separately but an estimated 40,000hp combustion turbine would be needed to generate electricity for the electric motors at PS9 and an additional $20,000,000 in power line construction would have to be financed. Most importantly it is concluded here (Ex. ATC-105at 9) that this Alternative (4.A) cannot provide power for less that the proposed purchased cost (from GVEA) of $0.05/kWh. Ex. ATC-105 at 9.

214. Alternative 4.B, Use Alternative Power, Such As Electrical Line from Dead Horse, for Northern Stations, contemplates the construction of power lines and the use of purchased power while converting some pump drivers to electric motors. The details of this sub-option are not explored further here since this option, as stated in the Draft Report, ". . . does not appear to be any economic benefit to pursuing this further at this time." Ex. ATC-105at 10.

215. The last two alternatives in Alternative 4 (4.C and 4.D) are also rejected in this Draft Report as not having "any economic benefit" and for the sake of brevity will not be detailed here.

216. Section 3.3 titled "Auxiliaries" has five (5) sub-sections (3.3.1 to 3.3.5) with one sub section (3.3.2) having further divisions. Sub-section 3.3.1 is titled, Improvements for Automation of Controls and, is the most relevant section in this Section to the issues in this instant case. Of particular interest is the citation to a 1997 Report titled, Control and Telecommunication Long Range Plan TAPS Instrument & Control System Conceptual Study (also known as the Bailey Report). Ex. ATC-105 at 10 describes the Bailey Report as providing in depth estimates for installation alternatives and benefits for various levels

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of automation. In addition, it states that the Bailey Report provides considerable reduction in personnel costs as a result of automation facilities while identifying that "other benefits remain to be worked." Yet this section has certain criticisms of the Bailey Report, such as:

> The simple functional analysis for personnel assigned to pumping oil using the assignments for the "Standard Cost of "Atypical" Pump Station would indicate that one person per shift could be eliminated at each location if Main Line Units were automated. This saving would not economically justify automating the Main Line Units as a stand alone project. It may be necessary and result in a general reduction in personnel costs as part of a broader scope automation project. Alternately, automation of the Unit Control Panels would be part of the installation of new drivers for the pumps. This has been included in the cost of alternatives with new drivers.

Ex. ATC-105:10-11.

217. As noted previously, this Draft Report provides no supporting documentation information that would aid in understanding the basis of the above claim. Without additional information (such as Work papers defining what is meant by the "Standard Cost of Atypical Pump Station," assumptions considered for personnel reductions, why Main Line Unit Automation would not include automation of the Unit Control Panels) it is impossible to determine the validity of this claim with respect to how many personnel could be eliminated with the introduction of Automation to the Alyeska Pipeline System.

218. Section 3.3.2 is titled Waste Heat Recovery and discusses the potential to utilize the waste heat of the turbine exhaust to provide Station Heating and Crude Oil Heating but is ultimately rejected since, "Installation costs would be roughly $60 million for six stations which would not be justified by the savings." Ex. ATC-105 at 11.

219. Section 3.3.3 it titled Building Systems and clearly states that "no economic evaluation was done for removing or simplifying the buildings." Ex. ATC-105 at 12.

220. Section 3.3.4 is titled Fire Suppression Systems and recognized that the current Halon fire suppression system will eventually go completely out of use with no anticipated direct replacement of Halon 1401 in use circa 1999. There is also a statement that a change from Halon to some future system is a life cycle replacement issue and not an efficiency upgrade. Ex. ATC-105 at 12.

221. Section 3.3.5 is titled "Other Life Cycle" and acknowledges that other life cycle replacements may be necessary, but are not included in this study. Ex. ATC-105 at 13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

222. Chapter 4 is titled Results and, not surprisingly, identifies the results of the studies. Section 4.1 discusses the Pump Station Configuration and identifies the best pump station configuration for future operation of TAPS and concludes that, "the cost of operating the PS 7, 9, & 12 combination [sic] is always less than the 6, 8, & 10 combination." Section 4.2 through 4.8 discuss the various Alternatives, as discussed above, but in all cases rejects all these Alternatives as having "no economic benefit[207]." Ex. ATC-105 at 14-16.

223. Chapter 5 is titled "Conclusions" and states in no uncertain language that the current Avon drivers are the preferred drivers for TAPS. The language in this section is strikingly clear and bears replication here:

> The current configuration of pump stations and the rampdown plan are the most efficient for now and the future. It is very beneficial to continue to fine tune the pipeline as a system as changes occur. Foremost is the need to continue to optimize the economics between fuel and DRA as prices, performance, and crude throughput change.
>
> Changing to more efficient drivers does not provide robust economics which would drive the change. The change does present close to break even economics at 11%. If C02 reduction can justify a project, then changing drivers can be attractive. . . . Considering CO2, installing a new large turbine at PS9 or electric drivers at PS 7 and/or PS 9 may be viable options.

Ex. ATC-105 at 16-17.

224. Additionally it is noted that implementing electric pump drivers "at PS 7 and/or PS 9" would entail "higher technical risks because it represents a significant change in equipment and adds dependence on the utility" (GVEA). The alternatives which considered the Solar Titan drivers is explicitly rejected as "not yet proven and may represent a high risk change." Ex. ATC-105 at 17.

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[207] It is noted that the results for alternative 4 states as follows: "The cost of operating with electric power at the price offered by Golden Valley is approximately break-even, the analysis shows a slight advantage if crude prices are high. . . . Because any advantage is dependent on crude price and the financial and operational risks are significant with this change, it is recommended that Alyeska remain with turbine drivers. Ex. ATC-105 at 15. Similar language is found in the conclusions section. To wit, "[t]he economics is tied to fuel costs because GVEA would establish the energy costs to Alyeska based on long term fuel contracts they would establish. If our fuel prices rise significantly later, this can be an attractive alternative, but if fuel prices stay low this is not attractive." Ex. ATC-105 at 17.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

225. The ultimate recommendation of this Draft Report is:[208]

> that future facility changes include a strategy to migrate to nearly "unmanned" operation. A simplified analysis indicates that the pumping oil function can be supported, especially with automated controls, by two operators on duty, four people total on site. As a strategy we should avoid installing equipment that is "least cost" but requires additional human effort on site for maintenance or monitoring.

Ex. ATC-105 at 17.

226. As mentioned above, an alternate 'Executive Summary" is also offered. Ex. ATC-105 at 21. This Executive Summary varies significantly from the Executive Summary on page 2. Page 21 states that this study was requested to provide a strategy for reinvestment of capital in TAPS by the Owners. This was not mentioned on page 2. The alternative Executive Summary states that the study provides technical and economic evaluations of opportunities for facility changes that could reduce cost of operations. It also identifies this study as mostly focusing on the economics of the pumping oil function. It mentions that it deals with the sensitivity to crude oil prices in two significant ways: (a) the cost of purchase fuel varies with the price of crude oil by a formula in the contract. Two different crude prices were used to represent the range, $9/bbl and $20/bbl and (b) the throughput varies with economics of North Slope production. *Id.*

227. The alternative Recommendations section clearly states the "[t]his study did not find "robust economics" for major changes in the facilities. Also identified are changes to pump station 9 that should be studied in detail, suggesting that a more efficient driver and incorporating heat recovery for utilities (among other changes at PS 9) are "marginally economic or non-economic changes but it may be prudent" to make such changes so that operations may be better positioned for the future. Also contemplated is the quest to integrate and fine tune the controls project plan and a recommendation that a detailed up to date life cycle replacement plan be prepared including both the pipeline and items inside the pump stations.

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[208] The document states that there may be reasons for capital changes other that economics and that these were not evaluated since the value is not clearly quantifiable. However, a for instance is given. To wit, if it is desired to reduced emission of air pollutants from the pipeline facilities for reputation reasons, purchased electrical power could be used at PS 7 and 9. *Id.* at 17.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

228. These two Executive Summaries seem to be opposed to each other since one recommends the use of the Avon pump drivers (Ex. ATC- 105 at 2) and the other suggests the replacement of the Avon drivers at PS 9 for future operations even though these changes are "marginally economic or non-economic changes. (Ex. ATC-105 at 21). How one report can represent two divergent conclusions is at best a conundrum. However, what is clear is that electrification even supported by the electric grid is not economic or marginally economic.[209]

VECO Control & TeleCommunications LRP Addendum Report

229. A February 22, 1999, report by VECO Engineering (C&T LRP Automation Group) validates the Bailey Report.[210] Ex. SOA-134. It lists systems that were recommended for upgrade in the C&T LRP (1997) and were implemented (some at Valdez) others line-wide such as upgrades: to the Remote Gate Valve control system; to the Digital Strong Motion Accelerometer (DSMA) earthquake monitoring system; and to the Leading Edge Flow Meter system for use in leak detection. In addition, a Transient Volume Balance leak detection system has been added and North Pole Metering. *Id*. at 14. At the time of this report $47 MM of the $53MM of Alternative D in the Bailey Report had been spent in control system-related capital projects. *Id.* It also lists projects that are in progress at page 16 and the stations which have been ramped down: 2, 6, 8 and 10. PS 12 is projected to be shut down in five years and PS 7 in ten years if throughput continues to decrease. *Id*. at 16. The C&T Long Range Plan (1994) and Conceptual Study (1997) have not been successful only from the perspective of never having been implemented. *Id*. at 4. It creates a five year plan for the project from philosophy development through implementation. Ex. SOA-134-at 31.

Strategic Breakthrough Study-Pump Station Automation

230. In the third phase of the proceeding a new exhibit was introduced. This purports to be a Strategic Breakthrough Study-Pump Station Automation. The study was not made a part of this record instead a four page document was introduced. This undated document is titled Strategic Breakthrough Study-Pump Station Automation.[211] The document states that the purpose of the study is to develop operator's recommendation

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[209] In their initial brief the Carriers agree that this study did not recommend facility changes.

[210] The document states that much of the automation and control equipment is obsolete and kept operational by highly skilled and innovative technicians who have even built work-around circuit boards for non-working equipment. It poses the question whether "Alyeska is in the electronics or oil pipeline business." *Id.* at 8.

[211] The joint chronology of exhibits dates the document as April 22, 1999. Ex. J-2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

for pump station automation. The background of the document states that "a functional review of activities generating costs such as was done for the Reinvestment Strategy Study shows that few, about four people per pump station are actually needed to "move oil." We should "picture success" as a station being operated with two people inside the station fence. Other necessary activity and support should be kept off the TAPS ROW as much as possible." Ex. ATC-899. This document states that the original design concept for the Pump Stations was to operate unmanned. However, during startup of the pipeline, more manpower was added after an incident with PS 8 and due to reliability concerns. The document states that now there is new control equipment technology and extensive operating experience.

231. The document (Ex. ATC-899) cites the Bailey Report and states that the FBU Strategic Breakthrough Team reviewed the Bailey Report. Ex. ATC-899 at 2. It states that the high level conclusions in selection of the best "alternate have not changed." Since some of the recommended automation work had already been done the cost of Alternative D from the Bailey Report dropped to $51 million (from $53M).[212] In addition, this document points out that some of the Urban Staff Reduction numbers were reduced due to staffing changes in a 1997 reorganization, which diminished staffing. The original study had staff reductions of 79 people and the current evaluation is 79 people. However, the VMT and Urban Staff reductions in the original study were 33 people, in the current evaluation they are down to 16 people. *Id.* Since the study could not account for fixed savings (savings in machine monitoring, incident reductions, throughput impacts, Halon usage and warehouse stock), these savings were reduced by 50%. The analysis assumed seven pump stations. *Id.* This document states that even with reduced benefits, automation was economic. Assuming minimum staff reduction of 70 would give a favorable internal rate of return. The document also points out that if 46 staff originally designated to be eliminated after ramp-down were added the internal rate of return would be even higher. *Id.* This document recommended, in addition to the recommendations of the Bailey Report, that the OCC Pipeline controller be moved to Fairbanks.

232. This exhibit describes the recommended automation improvements of Case D of the Bailey Report. *Id.* at 3. To summarize, the exhibit states that the intent of Case D is to "add enough instrumentation, control valves and automation to produce a system where control rooms are unattended, and rover duties mostly eliminated.[213] One goal of the case is to be able to run a pump station with no "operators" or rovers." The tasks of the maintenance personnel can be reduced to the point where they can take on tasks

[212] According to the study some of the recommended automation work has been done, i.e. DRA flow control and MLR2. *Id*. at 2.

[213] This included adding instrumentation to the non-MLU (Garrett and Solar) turbines. It also included improvement of the vibration monitoring equipment. *Id.* at 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

formerly assigned to the control room operator which are not related to instrumentation or control. This program would allow operational control of the pump station by the OCC. The new instrumentation would allow the data logging schedule to be reduced to once per 24 hours. New turbine instrumentation and control would permit OCC to safely start the main line pumps (MLUs), and to adjust speed of individual MLUs to avoid operating in critical speed or high vibration."[214] *Id.* at 4. Other intangible costs were listed. *See Id.* at 2-3. Other alternatives that had even more automation were not recommended because the additional manpower savings were offset by the large amount of additional instrumentation that had to be installed. *Id.* at 1-2.

233. Another interesting point in this document is that it has a paragraph on an implementation plan. The section is titled Implementation Plan. "Pick a station and begin automating it. Adopt the Case D as the starting point. The first station should be 3, 4 or 9. Pump Station 3 would be best because it would allow changes to be worked out for the three gas fired stations and allow the working of manning issues with stations available on either side if support is needed during the implementation phase. PS 4 could be next, followed by PS 1, PS 9 could be last. Use this first station to validate the cost and benefits and to find out what works and what doesn't. Then start implementing automation at other stations. If this is done a station at a time, the benefits will start as soon as each station is complete. This may cost more since "we won't be able to take advantage of moving a crew that is doing a fixed task from station to station. If we upgrade system by system at all stations, the benefits will not start until the last station is done." *Id.* at 4.

Emails September 1999

234. An e-mail from M. Kaminski dated September 10, 1999, with the subject line of Strategic Framework Scope notes the selection of Kenonic Controls Ltd. (Kenonic) for implementation of the "Strategic Framework." Ex. ATC-106.

235. In an e-mail to Alyeska from B. Howitt and D. Hisey, Senior Vice Presidents and Dave Laurence, Vice President and Chief Information Officer dated September 30, 1999 everyone is informed of the creation of a team for implementing a company-wide Strategic Framework for Control and Information Systems integration and updates. The vision of this team was to improve control, communications and business hardware/software, and the way data is exchanged between the control and other systems. The analysis will be conducted by Kenonic with the purpose of integrating as many systems as possible. The control systems listed are SCADA, Pump Station Control, Oil Metering, Bailey DCS, etc which are used to operate TAPS. Multiple business systems

[214] This included: turbine fuel metering, fire panel control electronics upgrades among others listed on page 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

are also listed: accounting, payroll, AFE, equipment maintenance, training, PassPort, etc. Ex. ATC-107.

Tour of Fort Knox gold mine Circa 1999

236. Testimony from a Carrier witness shows that on or about 1999 Pomeroy and his team "toured" the Fort Knox gold mine near Fairbanks. Tr. 8011:21-25. No reports were generated from this informal inspection. They were looking at whether there was capability with the local power generation utility to support providing power at PSs 7 and 9.

Strategic Initiatives Status Report

237. TAPS Strategic Reconfiguration Program is described in a Strategic Initiatives Status Report[215] dated March 2000. Ex. ATC-108 at 2. The TAPS Strategic Reconfiguration Program is identified as the name of a program consisting of several smaller programs. Several "upgrades" and "plans" are listed as being smaller projects, all integrated in the larger program known as Strategic Reconfiguration. Ex. ATC-108 at 2. Subsumed within Strategic Reconfiguration Program are: 1) Pipeline Control System Upgrades, 2) Revised Pipeline Maintenance Implementation Plan, 3) Revised Oil Spill Contingency Response Plan, 4) Pipeline SCADA Host Control System Replacement, 5) Configuration of Pipeline Terminal Control Functions and, 6) Optimal location of Pipeline Operations Control Center. Ex. ATC-108 at 2, 9.

238. In this document Alyeska recommends proceeding with work to develop an "optimal long range TAPS configuration strategy and implementation plan, definitive program costs and economic evaluations and a detailed implementation schedule." Ex. ATC-108 at 10. The report states that Alyeska will request approval of the TAPS Strategic Reconfiguration Program Phase I AFE for $3.1 million to do preliminary work to proceed to a point where an informed decision can be made to proceed to a December 31, 2000 go/no go decision point, and complete implementation at selected prototype locations by June 30, 2002. *Id.* at 10.

239. The report describes the "replacement of existing pipeline control systems to address obsolescence and high cost of ownership, and allow full pump station control capability from a remote location with retention of caretaker work force only. This will include a company-wide integration of control systems with business systems to provide real-time or near real-time information to required users." *Id.* at 11. The report lists as preliminary economics a ROM[216] costs of $47MM and ROM savings of $20 to $40

[215] ATC-108 is identified as a Status Report on the front page.

[216] ROM was defined as Rough Order of Magnitude at Tr. 890:11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

MM/yr (NPV range of $24 MM to $62MM). Concerning risks it states that the capital outlay required is "ROM $53 mm" and regulatory approval will be required to reduce response staffing levels below current minimums. The probability of success is "P=80." There is a preliminary timeline as follows: from May 1, 2000 to December 15, 2000, the plan was to develop control/business systems conceptual design (functional requirements); from December 15, 2000 to August 15, 2002, implementation of upgrades and related strategies for prototype location(s) and from April 15, 2002 to August 15, 2004, implementation upgrades and related strategies for the remaining locations. *Id*. at 11. The work completed section cites the Bailey report as reviewed by APSC in 1999 and states: "Studies provided preliminary economics and recommendations to proceed with upgrades." *Id.* This is a recommended option with high risk and high rewards.[217] *Id*. at 5.

240. The report describes the Pipeline Maintenance Plan as "development of a long range Pipeline maintenance strategy and implementation plan to support and compliment a migration to minimally manned facilities." This is to be consistent with Alyeska's overall equipment maintenance strategy designed to maximize planned vs. reactive maintenance by mobile regionally-based maintenance crews. *Id.* at 12. A revised maintenance plan consistent with the pipeline control systems upgrades had to be implemented by August 15. 2002 (preliminary timeline). *Id.* The ROM costs are $2-4MM and savings $2-5MM/yr. *Id.* at 12. Work completed cites to the Bailey Report. *Id.*

241. For oil spill response, the plan was to move to a caretaker mode at select facilities. *Id.* at 13. The ROM costs are $2-5MM and ROM savings of $3MM to 10MM/yr. *Id.* at 13. The oil spill response strategy is to be made in conjunction with the control systems upgrade. *Id.* The risks are listed as required regulatory approval which was perceived as contentious due to "perceived negative impact to response capability." *Id.* The timeline is in conjunction with control systems upgrades to implement oil spill contingency strategy by August 15, 2002. *Id.* Work completed cites to the Bailey Report. *Id.*

242. The next item in Strategic Reconfiguration involves replacing existing SCADA Host Control System with open architecture system including current technologies to avoid current issues with obsolescence, high cost of ownership, lack of redundancy, and limited disaster recovery and technical support resources. *Id.* at 14. The ROM costs at $3.4 MM with savings of $0.2 MM to $0.5 MM/yr. The benefits are described as improved reliability and reduction of potential for upsets/incidents. *Id.* at 14. This alternative cites the conceptual study completed in 1997 (C&T LRP) and reviewed/revised by APSC in 1999. *Id.* The report recommends separation of the existing Pipeline SCADA and VMT control functions to achieve efficiencies. *Id*. at 15. Additionally, the Pipeline Operations Control Center should be relocated to resolve

[217] The report does not recommend eliminating night security. *Id.* at 5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

problems such as suitability of existing structure, lack of redundancy, capability for disaster recovery, and availability of technical support resources. *Id.* at 16.

243. Personnel reductions are as follows (AF Nu. 180 Phase I): Base case a total of 180 personnel reductions (50 Pipeline, 100 contractor, 5 urban Alyeska, 25 urban contractor); Case 2 (Increased Headcount reduction) a total of 215 (50 Pipeline, 115 contractor, 15 urban Alyeska, 35 urban contractor); Case 3 (Maximum Urban Headcount Reduction) a total of 265 (50 Pipeline, 115 contractor, 50 urban Alyeska and 50 urban contractor); Case 4 (Related OSCP Costs Doubled) a total of 180 (50 Pipeline, 100 contractor, 5 urban Alyeska, 25 urban contractor); Case 5 (Regulatory Disapproval of OSCP Revision) a total of 145 (40 Pipeline, 75 contractor, 5 urban Alyeska, 25 urban contractor). Ex. ATC-108 at 17. All scenarios had a positive IRR from 29.3% for the base case to 22.8% for case 5 with a peak of 37.8% for Case 3. The payback ranged from 5.4 to 6.9 years. *Id.*

244. The report discussed further study for and decommissioning ramp down stations (ramp down stations 2, 6, 8 and 10). *Id.* at 22. Ramp down of PS was a recommended option described as high risk high reward. *Id*. at 5. The ROM cost of this initiative was $86.3 MM with ROM savings of $4.8 MM/yr. *Id.* at 22. The possible implementation at PS 8 or PS 2 was December 31, 2001.

245. It also included a recommendation to proceed with an "evaluation of the configuration options for mainline equipment (pumps and drivers) as part of the development of a long range TAPS reconfiguration strategy (TAPS Strategic Reconfiguration Program)." Ex. ATC-108 at 41. The report goes on to state that the work will focus on identifying changed conditions to take advantage of efficiencies or benefits to operation and maintenance. The "recommended course of action will enable detailed evaluation to be completed in support of the December 31, 2000 "go/no go" decision point, and provide sufficient information for possible implementation at a later date. Prior stand-alone conceptual engineering evaluations of potential upgrades to mainline equipment identified various possible minor incremental economic benefits. Although none of the identified alternatives presented a compelling economic case for proceeding, . . . ". Ex. ATC-108 at 41.[218] For instance, converting PS 9 to electric driver

[218] One initiative was gas generator upgrades at PS 7, 9 and 12 (replace the Avon/Cooper 1533 turbine gas generators) with Solar Titan turbines 18,000 HP. Only liquid fuel drivers were considered due to lower cost of gas-fired units at PS1 thru 4. *Id*. at 42. The ROM costs for this option were $50 MM the ROM savings "+$0.7 to - $0.2 MM/yr. with NPV range of +$13 MM to -$4 MM. Another initiative was to evaluate the feasibility of replacing the Cooper RT66 single stage reaction turbines at PS 7, 9 and 12 with Cooper RT56 two-stage turbines and gear boxes. Only liquid fuel drivers were considered. The ROM costs were $30 MM and savings -$0.3 to -$0.5 with NPV range in the -$5MM to -$10 MM. The next initiative was to evaluate the feasibility of replacing existing pumps and drivers at PS1 and 9 with GE LM 2500 drivers with matching pumps.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

is described as a second tier possibility with high risk and low reward. *Id.* at 5. Intertie PS 1 to NS power grid is estimated to be medium risk with low rewards. *Id.* This had not been previously studied. *Id.* at 71.

246. For system reliability purposes this report recommends evaluating the feasibility of a line-wide reduction in installed equipment to eliminate redundant equipment. *Id.* at 55. This is described as high risk high reward. *Id.*at 5. Section 10 of the report describes various corporate strategic initiatives or corporate realignment. *Id.* at 3. It states that Alyeska has begun implementing various alternatives to reduce costs. *Id.*at 89. Corporate headquarters realignment Phase I was described as reducing the size of Alyeska corporate headquarters through elimination of redundant or low-value work, consolidation with existing business unit functions, and consolidation of remaining functions/organizations. *Id.*at 90. ROM savings are $15MM to $19MM/yr. *Id.* Contemplated also were reductions in legal, external affairs, outsourcing administration of benefits and pension programs, outsourcing accounting, deferral of it projects. *Id.* at 92-96.

Meetings/Emails

247. In a TAPS Owners Committee meeting on March 22-23, 2000 at Sonora, Texas, strategic reconfiguration was discussed. Ex. ATC-109 at 4-5. On Strategic Reconfiguration, Dick[219] expressed support for developing an optimal plan for running

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It notes that only PS 1 and 9 can utilize or take advantage of the larger horsepower units. *Id.* at 46. The ROM cost $38 MM and ROM savings +$0.5mm to +$0.03MM/yr with an NPV range of +$9MM to +$0.75MM.

Another initiative was evaluating the feasibility of replacing one existing pump and driver at PS 9 or creating a super pump with a GE LM 2500 driver and matching pump. It adds that a second existing unit could be configured to full head as a backup. Noting that only PS 1 and 9 can take advantage of the larger horsepower units and the lower cost of gas fired units (at PS 1) provide less economic justification. The ROM costs $19 MM and savings +$0.6MM to +$0.05MM/yr. with NVP in the range of +$12MM to +$1MM. *Id.* at 47. Of particular interest in this case is the next initiative which is replacing turbines at PS 7 and 9 with electric drivers. The ROM cost $24 MM with ROM savings +$1.6 MM to -$1.8MM/yr. with NPV range of +$32 MM to -$36MM. The risks of this option are that the economics are dependent solely on fuel prices (lower costs yield negative economics). The contractual terms for electricity are take or pay and would obligate Alyeska to an 8-10 year period. The probability of success is P=50 (less than the other options). *Id.* at 49. The last initiative is to replace two existing turbines at PS 9 with electric drivers. The ROM costs are $16 MM and ROM savings +$0.9MM to -$1.3MM/yr. with NPV range of +$18MM to -$26MM. *Id.* at 51.

[219] Dick is Richard Rabinow, Exxon Pipeline Co.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the pipeline over the next segment of its operational life and noted the importance of starting such a thought process. Ex. ATC-109 at 5. Of note is a comment by Bob[220] that since TAPS is well along toward being paid for, the Owners may feel that the status quo is acceptable, rather than taking strategic initiatives, such as automation. "The Owners expressed uniform agreement that continuation with the status quo was unacceptable and strategic changes were necessary. . . . Meg noted that unit costs have to be reduced to extend the life of the slope reservoirs." Ex. ATC-109 at 6. As an interesting matter "Joe[221] applauded the APSC effort. He expressed support for an owner-operated system as a concept that needs to be considered in any 'strategic' discussion. . . . Meg noted that the 'vision' concept needs to come from the Owners. . . . Bob expressed support for further consideration of the owner-operator concept as part of this strategic work as a means of reducing costs significantly. The Owners discussed the implications of an owner-operator approach." [222] Ex. ATC-109 at 5.

March 31, 2000 – Overview for Ramp-down Stations

248. Exhibit SOA-431 discusses the requirements associated with ramped down pump stations. The TAPS Ramp-down Overview has specific instructions for ramp- down stations. The costs of ramped down pump stations are costs the Owners wish to include in their rates. Ex. SOA-431 at 243. The Overview states that there are "four underlying principles to ramp-down: (1) the process must be cost effective; (2) the process must follow Alyeska management of change procedures; (3) the process must be reversible; and (4) ramped down pump stations must be adequately maintained and monitored so that they can be returned to full operational status within 180 days. The last two principles are most important to equipment replacement." *Id.* at 245. This is to protect Owners' interests. *Id.* at 244. Additionally, the Overview states that ramp-down pump stations will not be "cannibalized by removing equipment and permanently using it at other pump stations." *Id.* at 245. "The Owners did not want the act of placing a pump station in a ramped down status to be irreversible, and that a pump station in ramped down status would not be determined by the government to have completed its use, which could have potentially led to several unwanted results: dismantlement of the pump station and non-expensable costs of the ramped down pump stations in the Owners' rates." *Id.* at 244.

Email April 3, 2000

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[220] Bob is Bob Malone for Alyeska Pipeline Service Co. the host of the meeting. Meg is Margaret Yaege of ARCO Transportation Alaska, Inc. Ex. ATC-109 at 1.

[221] Joe is Joe Monroe from Unocal Pipeline Co.

[222] This is the first evidence in this record of the changing relationship between Alyeska and the Owners concerning this project.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

249. J. Luchini, who was to become Program Manager for Strategic Reconfiguration sent an e-mail to W. Wilson an Asset Manager (Steward) (*see* Ex. ATC-110 at 12) on April 3, 2000, stating that the schedule was challenging considering the short time allowed for development of the long range strategy and the major activities that must be worked concurrently, e.g. OCC, OSCP, maintenance, staffing, and engineering." Ex. SOA-570.

Authorization For Expenditure-F180- May 2000

250. On May 18, 2000, Alyeska submited to the Owners AFE F180 to request funding to perform the initial program development for Strategic Reconfiguration and Asset Utilization Program.[223] Ex. ATC-110 at 1. The amount requested was not to exceed $3.1 million. *Id.* The Phase I request is to perform program development, preliminary engineering, and planning for Strategic Reconfiguration and Asset Utilization Program. This includes evaluating past configuration/asset utilization conceptual studies to develop a long range strategy and implementation plan for future system configuration. *Id.* at 2. The majority of the work will establish detailed functional requirements and system architecture for a controls and business systems upgrade and integration effort on the Pipeline and the OCC and complete definitive estimates in order to validate overall Program economics. *Id.* The work would include: (1) development of a system-wide TAPS reconfiguration/asset utilization strategy and implementation plan; (2) assist with development of a company-wide control and business systems "strategic framework" and integration strategy; (3) development of a strategy and implementation plan for maintenance; (4) development of a strategy and implementation plan for OSCP; (5) development of a long term staffing plan; (6) development of detailed control/business system functional requirements by location and system (to include resolution of various OCC issues); (7) preparation of a Phase II AFE for the detailed design, material procurement, and implementation for upgrade of selected prototype locations/systems. *Id.*at 2.

251. The AFE states that the costs associated with full implementation of the currently known/anticipated work items for Strategic Reconfiguration and the OCC are estimated at $53 million. *Id.* The known work includes upgrade of the control systems (pump stations and OCC) and the development/implementation of regional maintenance, oil spill contingency response, and staffing strategies. *Id.* at 4. The yet-to-be-determined alternatives are not included in the $53 million. Separate funding requests will be developed and submitted for these initiatives as they are identified and gain approval. *Id.*

[223] Alyeska annually develops a potential capital project list for the Owners to review, prioritize and determine the scope and timing of the projects. Project funding is requested in phases submitted to the Owners in an AFE. Ex. SOA-030 (AFE Control Manual Rev. October 31, 2000).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

at 4. The "yet-to-be-determined" alternatives may include such major initiatives as: the immediate removal of currently non-utilized facilities and equipment (idled pump stations); the upgrade of MLU pumps and drivers; the electrification of select MLU drivers, the installation of additional crude storage tanks; and the possible connection of select TAPS facilities to other available power grids for backup and/or power sale purposes. Based on the results of this effort to identify optimal configuration, additional major projects may be initiated for concurrent and/or subsequent implementation. *Id.* at 5-6.

252. In the justification section of AFE F180 it cites to the May 1997 "Control and Telecommunications Long Range Plan Conceptual Study" as having favorably selected alternative D. It describes this as the optimal alternative which was a partial pipeline control systems upgrade which affords significant operational benefits and substantial staff reductions, while improving operational efficiency. Additionally, it mentions that Alternative D had a compelling economic justification for proceeding with upgraded controls for the pump stations and the pipeline, specifically an internal rate of return of 44 percent and a post-project payback of 2.8 years. AFE F-180 explains that these recommendations were validated in 1999. Ex. ATC -110 at 7-8. The 1999 update estimated a potential internal rate of return in the range of 23% to 38% specifically associated with net reductions in the number of operations, maintenance, and support personnel required, avoidance of ongoing repair/replacement costs, decommissioning of support facilities and other efficiencies. It mentions that not yet quantified, but believed that the program will result in additional efficiencies through avoided maintenance costs and further reductions in the number of support services personnel required to ensure safe and compliant operation of TAPS. Ex. ATC-110 at 8. The primary driver for the program is economic, "specifically avoided operations and maintenance expense." *Id.* at 8.

253. The largest single element of the cost estimates is $960,000 for the controls engineering contractor to develop detailed functional requirements for the control systems, based on VECO's ROM of man-hours. *Id.* at 9. The $53 million broke down: $47 million for controls upgrade, $3.4 million for OCC controls upgrade, and $2.6 million for enhancements to oil spill response capability. *Id.* at 10. The project economics were discussed with a reported $53 million initial investment. "As the single largest currently identified activity planned under the overall Program, Pipeline control system upgrades (to include replacement of the Pipeline SCADA Host) was used as the primary component of the Program's economic evaluation. . . . [v]ariations of the two identified major sensitivities of the control systems work (e.g. Fairbanks Business Unit staffing levels and regulatory approval of a revised oil spill contingency response plan) were used to establish a range of potential economic benefits resulting from overall Program implementation . . . ." Ex. ATC-110 at 10.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

254. The Base Case[224] would have 180 staff reductions (150 field and 30 urban staff) with an IRR of 29%, an NPV $39 million, and a payback period of 6.1 years; Case 2 (Increased P/L & Urban Staff Reductions) had 215 staff reductions (165 field staff and 50 urban staff) with an IRR of 33%, an NPV $49 million, and payback period of 5.7 years; Case 3 (Maximum Urban Staff Reductions) had 265 staff reductions (165 field staff and 100 urban staff) with an IRR of 38%, NPV $62 million, and payback period 5.4 years; Case 4 (Related OSCP Enhancements Costs Doubled) reductions were not listed the costs of OSCP enhancements increased from $2.6 million to $5.2 million with an IRR of 28%, a NPV of $38 million, and payback period of 6.2 years; and Case 5 (Regulatory Disapproval of OSCP Revisions) would have 145 staff reductions (115 field staff and 30 urban staff) with an IRR of 23%, NPV of $24 million, and a payback period of 6.9 years. Ex. ATC-110 at 10-11. All of the IRR values exceed the discount rate (10% as specified at page 23) which would mean "accept proposal" under Alyeska's decision making model. Ex. SOA-30 at 58 (AFE Control Manual dated October 31, 2000).

255. AFE 180 contains a "COST CATEGORY DETAIL" identifying Expenses including Outside Engineering Services Engineering (Systems Integration), Item 2: Controls/business systems integration strategy estimated to cost $200,000. Ex. ATC-110 at 3. Item 2 is described in a section titled, Description of Deliverables (Attachment 2 of AFE F180) for the TAPS Strategic Reconfiguration Program. Ex. ATC-110 at 15-16. The description of Item 2 identifies that Alyeska Corporate IT group is developing a company-wide control and business system strategy known as the "Strategic Framework." Ex. ATC-110 at 16. It is envisioned that the Strategic Framework Final report will be presented in the form of a conceptual design with specifications, system architecture, schematics and, implementation plans. Item 3 lists as a deliverable a Long Range Pipeline Maintenance Strategy & Implementation plan. It states that the new technology will require a shift in maintenance focus from reactive to proactive to ensure the equipment remains functional (even though the design is self-diagnostic). This is driven by the change in technology and the number of system equipment items to be maintained in addition to the skill sets[225] and number of personnel required to do the

[224] The major assumptions of the Base Case: control system upgrades implemented at 6 pump stations and OCC; daytime caretaker operation/maintenance mode implemented for PS 3,7, & 9; permanent living quarters closure at PSs 3 & 7; regional maintenance strategy implemented with dispatched maintenance crews; existing contractor "baseline" crew positions converted to Alyeska employees; future OSCP strategy approved by regulatory agencies.

[225] Pomeroy explained the technicians were working in an analog world and would need new skills because of the new control and data collection systems. Tr. 7886:18-7887:6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

maintenance work (changing from assigned personnel on operation to maintenance).[226] *Id.* at 16. Next, Item 4 lists as a deliverable a Long Range Pipeline Oil Spill Contingency Response Strategy & Implementation Plan. This included identifying manning levels and locations and descriptions of physical and/or administrative changes required for implementation such as enhancements to equipment condition monitoring, leak detection systems, installed physical barriers, response capabilities, pre-staged materials and equipment and mutual aid agreements.[227] *Id.* at 18.

256. AFE F180 lists as Expenses for Outside Engineering Services, Engineering (Controls), Item 6: Functional control requirements by location/system as costing an (estimated) $960,000. Ex. ATC-110 at 3. In Attachment 2, the Description of Deliverables provides:

> An important component of the overall TAPS Strategic Reconfiguration Program is the development of a functional description of the planned improvements for Pipeline and Pump Station control systems, including opportunities for integration with business systems. The control system improvements will be based on the Control and Telecommunications Long Range Plan (C&T LRP) Conceptual Study issued in May of 1997, Appendices, Volume 1, Appendix A: Scope of Work- Descriptions. The systems comprising the pump station scope are listed in Section 4 of Appendix A . . . The alternative identified as optimal is Option "D" as described in Section 3.1.4 of the C& T LRP. It should be noted that this option will provide "improved operational efficiency" for the pump station control systems only. The possible replacement of the Pipeline SCADA Host MV20000 control system is described in the "Enterprise SCADA" system in Appendix A and is to be maintained as a stand-alone scope of work. . . .
>
> The report will also provide a basis for the scope description of the Phase II AFE for the controls and business systems upgrade and integration. The Phase II AFE will subsequently fund the development of the detailed

[226] The anticipated optimal strategy was a "flexible and non-stationary maintenance team using equipment condition data extracted from the new control systems to predict possible failures in sufficient time to take appropriate action to mitigate the problem before it impacts operations." *Id.* at 17. The new plan would include manning levels based on planned "predictive" maintenance using equipment condition information gathered from the new control systems. *Id.* The plan was to look into the possibility of establishing maintenance support centers.

[227] Witness Pomeroy for the Carriers testified that this is the first time that there is a link between regional maintenance and regional oil spill recovery. Tr. 788:12-22.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> engineering (as functionally defined in the preliminary engineering phase) and the implementation of the upgraded controls at the initial pump station.

Ex. ATC-110 at 19.

257. Thus, AFE F180 was for funding preliminary engineering for automation and controls. The "yet-to-be-determined" initiatives were not funded by this AFE. Updating the control systems and automation could be done without changing the existing pump equipment as can be determined from the documents and Pomeroy's testimony. Tr. 7887:7-8.

Keeping you posted Memo

258. In a May 24, 2000, keeping you posted memo J. Luchini, Control Systems Upgrade Program Manager states that the Strategic Reconfiguration Program began as the Control and Information Systems Integration and Update project to develop a company-wide "Strategic Framework" for upgrades to the control and business systems. He goes on to state that in late 1999, Bob Malone requested that the scope be expanded to determine the optimal future configuration and asset utilization for the entire system. Ex. ATC-111.

Approval AFE F180

259. AFE F180 was approved by the Owners on June 14, 2000. Ex. ATC-112.

July 2000

260. In a July 19-20, 2000 meeting on future asset configuration the participants were asked for assumptions on what the pipeline would look like ten years into the future or more (year 2010 and beyond). System wide: control system and fire protection system upgrades would be implemented; facility footprint would be minimized at all locations. Additionally, there would be cold restart equipment sites and regional support centers. Pump station 1, would have electric drivers on booster pumps contingent on inter-tie to the grid and on-site power generation on stand-by, electric pump drivers at PS 3 and 4 with a generation plant for both at either location, pump station 9 would have electric or fuel gas drivers conversion. Ex. ATC-113 at 3-4.[228]

Kenonic Control System Strategic Framework

[228] *See also* Ex. ATC-900.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

261. Kenonic produced a Control System Strategic Framework Final Report (Rev 0) (Ex. SOA-156 and ATC-114) on August 2, 2000.[229] This report deals with control, interface and communications components.[230] Ex. ATC-114 at 7. The vision was to develop an architecture that facilitates the transfer of information from any system (data source) to the end user (application or human user) so that the end user has the right information to make a decision at the right time. *Id.* at 8. The real-time enterprise provides an information network that facilitates access to real-time control system information by any one. *Id.* at 7. Additionally, this report shows personnel field savings of 136 employees.[231] Ex. ATC-114 at 103. The report emphasized the importance of working with Alyeska staff in developing the CSSF architecture. Ex. ATC-114 at 42. Kenonic used the Bailey Report as referenced documents. Ex. ATC-114 at 32, 118.

262. This report states in the Introduction section that:

> As a result of analysis (Appendix A) of existing systems, industry trends, identified opportunities, and data requirements, alternatives (Appendix A) for the CSSF were identified and evaluated, and ultimately recommendations and guiding principles (Chapter 4) established. The analysis and recommendations are key to establish standard architectures (Chapter 5) for the CSSF for each of the major operating facilities of APSC. Specified with these architectures, are the technology and topology industry standards that are applicable for the specific control, interface, and communication components.

Ex. ATC-114 at 7.

263. The high level cost estimates in the report were plus or minus forty percent accuracy at best. Ex. ATC-114 at 7, 46. The ROM costs are $69 million. *Id.* at 46, 103. The report states it will take up to four years to complete the project and in preliminary engineering a more detail schedule would be developed. Ex. ATC-114 at 40. However,

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[229] The evidence in this record supports a finding that AFE-F180 funded the Kenonic Control (Kenonic) studies. Ex. ATC-898 at 18:15.

[230] Pomeroy testified that Kenonic was a principal component in the definition and cost estimates for hybrid. Tr. 7893:3-4.

[231] The Carriers argue in their brief that only 35 staff reductions can be attributed to upgrading the pump station controls. However, that is not a valid comparison since they themselves admit that the report promoted changes to all communications systems of the pipeline. Kenonics recommended an upgraded of Alyeska's IT systems, specifically, SCADA; VMT Local Process Control; Pump Station Local Process Control; Integration Layer; and Metering and Measurement. *Id.* at 38-39. Thus, the total number of reductions specified in the report should be credited.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

most of the individual work programs, can be executed over a two or three year duration. Due to interdependencies between the programs a longer period is suggested. A shorter schedule (2 or 3 years) would incur a premium to "fast track" the project. A four year duration is the best combination of costs and benefits. *Id.* at 40.

264. In combination with the SCADA master, the SCADA sub-master allows complete remote control capability. *Id.* at 27. The controls and automation upgrades would facilitate predictive maintenance. *Id.* at 56. The study at page 181 notes potential costs savings in the range of tens of millions dollars annually from maintenance management and predictive management specifically and recommends further study of this matter. The study discusses the fact that at the time the study was prepared there were complete machine health monitoring packages which included both hardware and software, so that a turnkey package could be installed. *Id.* at 199.

265. Comparing this Kenonic Report to the TAPS Engineering Manual it appears this document would be consistent with conceptual engineering. Ex. SOA-178 at 59. One sensitivity recognized in the report is that technical resources with the right skills are in short supply to perform integration and automation work. *Id.* at 21.

Minimum pump station footprint

266. A memo confirms the scope of the conceptual study for minimum pump station footprint and/or alternate pump station configuration and is dated August 25, 2000. Ex. ATC-115. The background section points out that the maintenance costs of infrastructure at the pump stations, buildings and utilities is "approximately 60% of the total cost of a typical pump station. It claims that these expenditures do not directly contribute to moving oil, and it is not a cost that directly adds value to the operation and thusly, there is an incentive to minimize this cost. Ex. ATC-115 at 1. The scope of the study is to determine the minimum facilities needed to move oil at a pump station. It is assumed that support facilities, including living quarters for personnel can be located elsewhere (not at the pump stations). *Id.* The document lists four alternatives. Number 1, do nothing. Number 2, minimize facility footprint, which required identification of "mission essential" equipment and facilities to complete the core mission and discontinue operations of nonessential facilities. Alternative Number 3, assumes a new pump station design by assuming a "current PS is lost due to a catastrophe. The new station would consider efficiencies in current pumps/drivers, control systems, modular construction, piling foundations, remote operation, absolute minimum footprint, etc. *Id.* Number 4, to determine benefits of "demo existing facilities and replace w/new pump station design incorporating reduced footprint." The initial study is to include ROM costs and will be done with baseline resources augmented by external personnel funded by the Strategic Reconfiguration AFE. Note that if this is referring to AFE F180, it specifically stated it was not funding any studies for station modifications. *See supra* P 250.

October 2000

20140227-3052 FERC PDF (Unofficial) 02/27/2014

267. A document shows that in October 2000, there was a meeting to discuss the rotating equipment control system and predictive maintenance.[232] The notes indicate the equipment discussed and the recommendations. The GG, RT, pump and other matters were discussed. A number of recommendations were made as to which specific instruments, monitors were needed for partially attended or "unattended" operation. Ex. SOA-685 at 3-4. For example, changes were not recommended on vibration instruments for the GG (Avon gas generators) but exhaust gas temperature is the most important monitoring parameter. Additionally, it was noted that the Garret Generators have very few failures but are under-instrumented with a recommendation to add vibration sensors on each gearbox, Garret turbine and generator. *Id.* at 3. Rolls (Cooper), Woodward were potential suppliers for upgraded control systems for the main line units. *Id.*

Owners meeting

268. Strategic Reconfiguration was discussed in a December 12, 2000 owners committee meeting. Alyeska is to submit an AFE for Phase I of its plan by January 1, 2001. Ex. ATC-116 at 5. The estimated cost of the program is $50 to $70 million for control system upgrades. In addition, Alyeska is to submit its analysis of the transition from 3-unit operation to 2-unit operation for OC review and approval. *Id.* It will also discuss with BPXA, the PBU operator, the possibility of obtaining power for PS 1 from the CPS. *Id.*

269. The purpose is to provide a status update of SR; obtain concurrence/understanding of the approach, methodology and direction; and obtain support on a few items that are critical to the ongoing work. Ex. ATC-117 at 2. The vision is to build flexibility to readily adapt to changes in product, throughput, technology, support infrastructure, resource availability so that the optimal return on investment can be obtained. *Id.* at 3. In what appears to be a slide (Ex. ATC-117 at 5) Strategic Reconfiguration is described as a control system replacement and upgrade, a long range facility configuration/utilization plan (operating facility reconfiguration and ultimate configuration of ramp down facilities), a revised maintenance strategy, a revised operations strategy a revised oil spill contingency plan response strategy and a revised staffing strategy. The reasons given for SR are: obsolescence of the control system and change in volumes and properties (2.1 MMBPD in 1989 and 1.0 in 1999 and declining); higher wax precipitation rates, higher percentage of resid, new oils with different characteristics, and potentially white crude. This slide indicates a preliminary "ROR calculations indicate a 15% to 27% return on an investment of $50-$70 million." Ex. ATC-117 at 6.

270. Of interest is a slide which shows the 1989 mainline pumps required 28, with 14 maintenance centers and 14 manned control rooms. The 2000 mainline pumps required number is now 8 with 9 spare mainline pumps, 9 maintenance centers and 10 manned

[232] Attendees: Jerry Dehaas, Tom Turnipseed, Teve Schudel, Roland Kiddle, Brad Spencer.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

control rooms.[233] *Id.* at 9. The projection for 2010 is 4 mainline pumps required, 4 spare mainline pumps, 6 maintenance centers and 2 manned control rooms. *Id.* The SCADA host replacement would start the second quarter of 2001 and completed in two years. Fire detection/suppression would start in the first quarter of 2002 and last 18 months. Ex. ATC-117 at 10. During this time period they are working on decommissioning pump station 2. *See id.* at 10.

271. Another slide shows the potential long range configuration by 2010 as follows: PS1, PS3, PS4 and PS9 operating one mainline unit; PS5 operating relief facility and cold restart contingency; PS7 and PS12 provisions for cold restart; PS2, PS6, PS8, PS10, Berth 1 removed. Additionally, the operations are controlled by a single control room. For maintenance, the footprint is minimized and modularized to facilitate maintenance; capacity/property changes are handled through modification or addition of modules; and spare/contingency operating equipment online. *Id.* at 12. In addition, the maintenance strategy calls for increased equipment monitoring and trending capability; increased planned maintenance (added infrastructure to allow greater response time to equipment failures), reduced equipment and facilities requiring maintenance. *Id.* at 15. In terms of staffing they are contemplating eliminating the 24/7 requirement for field operations and maintenance. The integrated controls and business systems will reduce manual data manipulation, maintenance and OSCP will utilize more local resources along the pipeline (urban schedule for maintenance where possible).

272. The notes from the meeting confirm that the project was for control systems upgrades. The note also states that Alyeska is going to submit an analysis of the transition from 3-unit operation to 2-unit operation for approval. Further, Alyeska was going to discuss with "BPXA, the PBU operator, the possibility of obtaining electric power for PS 1 from the CPS." Ex. ATC-116 at 5. In this meeting Dick Rabinow noted (in relation to control systems upgrades) that the proposed timetable may be difficult to meet, given the complexity and magnitude of the proposed program. Ex. ATC-116 at 5.

273. In December 13, 2000, Alyeska worked with the JPO to develop a cold restart procedure for the equipment. Ex. SOA-604.

274. The Strategic Planning Team is formed in December 2000, comprised of Carriers' representatives and some Alyeska staff. Pomeroy called this team the Owner Planning Team. Tr. 8067:6-17; 8067:18-25.

Preliminary Conclusion circa 2000

275. Therefore, it can be concluded from record evidence that the Carriers knew at this time frame: (1) that the pipeline was well along towards being paid for, the Carriers

[233] The Carriers are concerned with costs but it is noted that they had already gone from 28 pumps to 8 pumps by the year 2000.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

wanted to reduce costs to extend the life of the slope reservoirs;[234] (2) that Strategic Reconfiguration was a program to update the control and business systems, replace the SCADA Host control system, separate the VMT and SCADA control functions and relocate the OCC, including developing maintenance and oil spill contingency response plans; (3) there were no robust economics for major changes to the facilities (replacing Avons); (4) electrification of some pump stations (where electric supply was available) had been rejected as non-economic;[235] (5) ramp-downs of some stations were being considered; (6) fire suppression systems would have to be upgraded; (7) Bailey's alternative D was still the recommended alternative since more automation would not necessarily be more beneficial due to increase in costs and risks; (8) the recommendation was to undertake automation one pump station at a time; (9) automation would take four years, a shorter schedule would incur a premium; (10) there was a short supply of skilled workers to do automation; (11) there were concerns that four years was too challenging (12) staff reductions were attributed to management reduction initiatives and automation (13) there are regulatory risks, especially for the OSCP. However, the Carriers were still interested in studying configuration of the pumps. Based on all the studies conducted at the time, they also knew proper scoping and front-end loading were critical to the success of the project.

276. Alyeska reported in 1999 that a new gas turbine would cost $4 million. Ex. SOA-143 at 5. This is a fraction of the ultimate cost of the SR project.

277. As Anadarko correctly points out, the Carriers knew that the original design of TAPS was working well. The Carriers also knew it was very risky to operate unmanned pump stations and such an approach should not be implemented unless it could be proven to be safe and produce real cost savings.[236] Pomeroy testified that the greater the level of automation the greater the number of defects that would have to be resolved. Tr. 7860:16-19. Therefore, it is concluded that the Carriers knew that automating TAPS was complex and required more than just simply installing pre-wired truckable modules. They also knew that the complexity level grew with increased level of automation.

278. Howitt corroborates the conclusions of the 1999 Reinvestment Strategy Study that the economics did not support the change to electric drivers. Ex. SOA-19 at 47. Pomeroy testified that during conceptual engineering they were aware of the potential advantage of the legacy equipment (the legacy equipment generated substantial heat which could be recovered and used to provide heat to the pump stations and help

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[234] This is evidence of production affiliate considerations not ratepayer interests.

[235] Note that the option studied up to this time involved solely electrification of two pump stations 7 and 9 and tying PS 1 to the power grid.

[236] Anadarko IB 51.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

ameliorate any oil cooling problems, such as waxing, as flow decreases) but did not include it in their analysis of the project ultimately undertaken. Tr: 8108:18-25. *See also* Tr. 3720:8-17.

279. Anadarko is also correct that the reconfiguration of the pipeline had begun long before the SR project was conceived. The VECO study confirmed that the upgrade to the control systems would "ensure that each key person within Alyeska, regardless of location, will have access to information, critical to their respective business unit or operation, in a timely manner." Ex. SOA-134 at 23. VECO also put the Owners on notice that the upgrades to the control systems would take approximately five years to complete, including four years from preliminary engineering through implementation. Ex. SOA-134 at 31.

280. Additionally, Anadarko is correct that the Strategic Initiatives Status Report concluded that $20 to $40 million a year could be saved through automation of the legacy equipment. Ex. ATC-108 at 11. The report recommended implementation of the initiatives "at selected prototype location(s)." Ex. ATC-108 at 10. A reasonable utility manager would have studied this further. The Carriers did not do this.

281. Kenonic in the August 2000 report pointed out that there was a shortage of technical resources with the right skills to do the automation work. It is found that the Carriers knew that skilled resources were in short supply in Alaska and that this could make it difficult to implement the project to automate TAPS. This became an issue for the project.

282. A cold restart procedure was possible with the legacy equipment.

3. *What happened in 2001*

283. An e-mail from Glen Pomeroy, dated January 11, 2001, states that as part of the SR program he is looking into going to two unit operation at facilities with three units (PS 3 and 4). Ex. ATC-118.

Owners Technical Review January 22, 2001

284. In an Owner technical review meeting on January 22, 2001, the Kenonic Control System Strategic Framework document was discussed (Kenonic, Ex. ATC-114). The specific scope of the project included the OCC SCADA; Valdez Terminal SCADA; Pump Station SCADA; and Data Acquisition and Process Control Systems at Valdez and the pump stations. Ex. SOA-233 (same ATC-119). The cost of the project was estimated at $70 million (including Valdez, without Valdez $63.8 million) including a contingency, taking 4 to 5 years to complete. *Id.* at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

285. In reviewing the proposal, there was criticism that the material provided was too general and little detail was provided in the form of an implementation plan. *Id.* "From past experience on similar upgrade projects it appears that the overall scope of the Alyeska project is too ambitious for the schedule. For the project to be completed in four to five years, significant effort would need to be performed in parallel, with the high probability that the pipeline services might be disrupted." *Id.*

286. The recommendations section states that there are numerous unanswered questions including whether "the control upgrade insure that the manning levels can be reduced, or will you end up with a fully automated and fully manned site?" Additional concerns included whether there were "regulatory issues that would prevent you from reducing staff." It concludes that "[n]either Al nor I see this project being designed, procured and installed in the 4 to 5 year time period. If this is the case, then cost overruns are very likely. Once you start down this path to upgrade your controls and SCADA system, it is very difficult to stop. Knowing your requirements on the front-end is critical." Ex. ATC-119/SOA-233 at 4.

Kenonic-Control and Business System Upgrade #7017

287. The record in this proceeding contains a draft (Rev A) document dated January 19, 2001. It appears to be a Kenonics prepared specifications attached to requests for proposals. On the lower left hand side the document has the following language: Alyeska Pipeline 7017 Control and Business System Upgrades. Ex. ATC-751. The purported meaning of this document had to be determined based on its language since it does not have a cover page stating what it is. The final document is not in this record. The scope of work involves determining what equipment (both software and hardware) needs to be replaced to achieve full automation of the existing Main Line Unit (MLU) equipment (Avon turbines with associated reaction turbines and mechanical pumps) at operating pump stations. As stated in Section 1.2, the intent of the Owners is to use common integrated control architecture for all the pump stations. Ex. ATC-751 at 7. The specifics on the exact operation of this desired control system is not finalized: "Each pump station that uses gas turbine driven electric generators shall consist of an overall electric system supervisory controller. It is unclear at this time whether this function will be a subsystem of the overall station controller, utility controller, or operate as an independent controller. This specification includes this controller as part of the scope of supply however, there is a possibility that this item may be removed in the future. The Vendor shall include this item as a separate bid and cost." Ex. ATC-751 at 7.

288. While the exact final configuration of the control system is still being thought through at this time, control points and data collection targets for MLU operations are identified in this document. For example, the Avon 1533 with the RT-66 power turbine Unit Control System will have the ability to remotely start and stop the MLUs, control the speed and fuel consumption of the MLUs, have the capability of emergency shutdown, monitor vibrations and many other monitoring functions. In terms of the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

overall replacement of the controls system, this document is limited to the upgrades necessary to achieve total remote control of the MLUs and accommodate a reliability centered maintenance (RCM) program. Ex. ATC-751 at 20-23, 2.

289. Interfaces known as Human Machine Interface have defined functional descriptions for each system being automated. Access to the Human Machine Interfaces is available both at the remote pump station and the operation control center. *See* ATC-751 at 26, 49, 74, 99, and 121. New data measurement devices are being added to the MLUs to achieve full remote operation. A list of proposed discrete signals (inputs and outputs) that will be monitored is described for each system: Gas Turbine Main Line Pump (ATC-751 at 28-32), Gas Turbine Injection Pump (id. at 51-58), Gas Turbine Fuel Gas Compressor (*id.* at 76-83), and Gas Turbine Electric Generator (*id* at 101-109).

290. In essence this document describes the upgrades to sensors and control equipment necessary to achieve total remote control operation of the existing MLUs with control exercised at a remotely located OCC or locally at the pump station (known as Station Control Panels). In addition, the proposed upgrades of the control system will allow Alyeska to implement a reliability centered maintenance (RCM) program. This document is equivalent to the last link in the chain of automation. That is, this report deals with the instrumentation that is necessary between the MLU and the pump station control panels to collect the necessary data to achieve remote control.

Emails February 2001

291. In February 6, 2001, Pomeroy is trying to obtain funds to collect data at PS3 and 4, this data would facilitate the permitting process to go to single unit operation at these two pumps. Ex. ATC-120.

292. On February 20, 2001, there is an email listing a number of vendors for Unit Control with bid packages. Ex. ATC-753 at 2. Jerry DeHaas responds on February 21, 2001, stating that what is needed is a company who knows how to take hardware supplied by vendors, "integrate it, and put it together in a value added package." He also suggests that the way to go is with common hardware (PLC's) and points out the integration has to be site specific. Additionally, he has specific comments about the vendors. *Id.* at 1.

Owners meeting

293. The owners met in February 2001 and outlined objectives to improve operations and performance and formed an Owners Special Team for this purpose. Ex. ATC-124 at 3.

Review of Unplanned events-April 2001

294. In an undated document which seems to be from early 2001 (Ex. ATC-122 at 2 a review of unplanned events for a six year period from 1995-2000 and economic evaluation using fall 2000 throughput projections) there are recommendations to remove

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the third pump at PS1, 2, 4, 9 and 12 and reducing maintenance at various locations since these pumps are no longer needed.[237] Ex. ATC-122 at 1-3.

Owners Meeting

295. In a May 9, 2001 Owners meeting they were discussing streamlining Alyeska's operations. Ex. ATC-123.

296. Kenonics received proposals for controls from ABB Automation, Foxboro, GE Global Systems, Honeywell IAS, Petrotech, Rolls Royce Energy Systems and Solar Turbines. Ex. ATC-754; ATC-755. The costs of the Kenonic proposal increased to $150 million based on the response to the RFPs. Ex. ATC-757.

June Report

297. The Owners Special Team submitted a report on June 11, 2001. Recommendations included having the Owners Strategic Planning Team work with on the planning process. This report indicates that there were some events in 2000 which contributed to stressed relations between Alyeska and the owners. The principal one being $50 million operating budget overruns for 2000 and higher than expected budget for 2001. Ex. ATC-124.

Emails June 2001

298. On June 12, 2001, an email indicates that there were a number of proposals received on May 21 for the Turbine Unit Controls (seven vendors). Ex. ATC-754.

299. An e-mail from P. Flood dated June 19, 2001, identifies the members of the new Strategic Planning Team and states the team will work on "Bold Steps" and "Strategic Initiatives." Ex. ATC-125 at 3. P. Flood of Conoco is the facilitator and organizer of the team, and J. Ray of Exon is a member. Ex. ATC-21 at 3-4. G. Pomeroy and J. Allison from Alyeska are also members. *Id.* at 4.

Costs for Control System Upgrades

300. In two documents dated July 2, 2001, Kenonic provides cost estimates summaries for the control system upgrades. Ex. ATC-756 provides a cost estimate of $75,143,319. Ex. ATC-757 provides an even higher estimate based on Stages I and II. The estimate now is up to $148,884,941. The major difference is that the detailed engineering costs for a number of items have increased.

TAPS Strategic Reconfiguration

[237] The Joint Chronology dates this document to April 24, 2001. Ex. J-2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

301. A document dated July 2001 with a title TAPS Strategic Reconfiguration states that "[t]he Peer group recommended separation of the control systems into individual systems for stand-alone evaluation and funding. It also states that an AFE for conversion of pump units at PS3 and PS4 to high capacity pumps with rim cooling has been developed and is in signature routing. Ex. ATC-129.

July 24, 2001 Memo

302. An automation consultant, J. Edmundson states in a memo dated July 24, 2001, that under AFE F180 ($3.1MM) Alyeska contracted Kenonic Controls to write a Control System Strategic Framework (CSSF) document providing specification of an ideal control system replacement for Alyeska. Ex. SOA-470. He states, that after an initial review, Kenonic developed six separate bid packages, received, and reviewed bids for the same. The results of the bids were presented in an owners meeting. He reports that Alyeska is planning to ask for further funding ($4MM) to finish this work by "2Q01" and submit an AFE to replace all their control systems. Edmundson states that Alyeska has split the system replacement into 2 stages. Stage I is estimated at $100MM and includes: replacement of the SCADA host, turbine controls, station controls, RGVs, metering and Fire & Gas systems. The second stage has not been estimated yet but includes the replacement of the pump station utility controls, the VMT Bailey system, electrical control centers, and environmental reporting systems.

303. According to his belief, the project team went beyond the need to replace obsolete, un-maintainable hardware and decided on a completely new control system. Ex. SOA-470 at 1. He recommends use of the Aspentech SCADA/DCS system in use in the North Slope. He states that this allows use of state-of-the-art operator consoles on a variety of PLCs, RTUs, and DCSs. This could be used to replace the Data General MV20000 system and still keep the underlying Square D PLCs which are still serviceable. According to the memo, this would avoid "the major expense of disturbing I/O wiring, re-FCO'ing the system, and documentation." *Id.* He estimates this cost $4MM. The turbine control panels could be replaced using the "lead of Jim Stewart's design at CCP and CGF." This is standard off-the-shelf GE/Woodward Mark VI system at a cost of $250 M each. The total for 12 turbines would be $3 MM. *Id.* Replacement of the fire & gas systems is mandatory with a cost estimate at $17MM. Again, he states that metering and station control systems should be evaluated individually and replaced only as needed. "The Daniels flow computers are still in use at Prudhoe and he sees no reason to replace them. Edmunds asserts that control system replacement is a costly endeavor due to re-wiring, documentation, FCO and facility interruption issue. This should be done only as a last resort not because "it is not from the same vendor." *Id.* His rough estimate is $24MM and states that even if this figure is doubled it would still be less than the requested $100MM. *Id.* at 2.

TAPS SR – Long Range Configuration/Utilization July 2001

20140227-3052 FERC PDF (Unofficial) 02/27/2014

304. This document under the heading Long Range Configuration/Utilization states that an initial hydraulic analysis of combinations of 2-unit and single unit operations with and without DRA was completed. It also mentions that a stochastic modeling of single unit operation at PS 7 and PS 12 is being conducted. Ex. ATC-129.

White Paper on Single Unit Operation

305. An undated document describes how maintenance expense and control automation savings can be achieved by removing the spare pump units while keeping the capacity at 1.50 mmbpd.[238] Ex. ATC-131. Based on hydraulic studies the following recommendations were made: high capacity impellers would be installed at two pumps at PS 9; air quality permits would have to be obtained for rim cooling at PSs 3 and 4; at PS 3 two pumps would be modified to high capacity configuration (one pump was already high capacity); spare units would be removed from PS 7 and 12, leaving a single half head at each station; the feasibility of a high capacity rotor with lower suction pressure requirements for use at PS 1 would have to be evaluated. *Id.* at 2-3. According to the document, the recommended configuration provides for throughput capacity of 1.50 mmbpd, the same capacity available after the ramp down of PS 6 in 1997. Maintenance and control savings will be achieved as a result of the reduction in the number of spare pumps. The upgrade of the existing pumps to high capacity pumps at PSs 3, 4 and 9 will increase the amount of time these stations can be operated with a single pump, resulting in additional maintenance and fuel savings. The stochastic model showed that there is minimal impact associated with removal of the spare units at PSs 7 and 12. The model also showed greater impact if spare units are not maintained at PSs 3, 4 and 9.

Email August 20, 2001

306. In an e-mail dated August 20, 2001, W. Tonkins asserts that they took a second look at installing two pumps at PS-9 and there is no economic incentive to modify two units. Thus, the recommendation is to modify only one, making unit 3 a super pump. Ex. ATC-133.

SR White Paper

307. An SR white paper dated September 2001, mentions that a supplemental AFE has been requested with an approval date of October 5, 2001. It also states that control system work is being held at its current status pending approval of the supplemental AFE. The Oil Spill Contingency Plan (OSCP) direction and strategy are being coordinated with the Strategic Planning Work Group. The Long Range Configuration/Utilization discusses the fact that the rotor in unit 3 at PS 9 has been replaced with a high capacity rotor allowing single unit operation. It states that this change was recommended from the

[238] The Joint Chronology dates the document as August 17, 2001. Ex. J-2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

hydraulic analysis completed last month. Information is being gathered to determine the service factor for different manning conditions at pump stations and to identify changes that may be needed to implement different manning concepts. Ex. ATC-134.

Engineering Report on Control Systems Upgrade-September 10, 2001

308. How data moves from the Pump Station control panel to the OCC as well as signals originating from the OCC to individual controlled machines (i.e., remote gate valves, security cameras, pressure monitors, etc. . .) is the subject of other studies. One such study is included in the record evidence in Exhibit ATC-752. This engineering report states that SR includes the Control Systems Upgrade Project which includes the: OCC/SCADA; VMT; pipeline (pump stations and remote gate valves) and process data historian. Ex. ATC-752 at 10. Exhibit ATC-752 is a compendium document of the overall controls/SCADA replacement plan titled Pipeline Controls Functional Description. Exhibit ATC-752 is a conceptual engineering[239] document dated September 10, 2001, that identifies the necessary monitoring points and instrumentation needed to collect system operational data to achieve total remote control of the entire TAPS system while utilizing the existing MLU to move crude oil from production fields to Valdez.

309. While these upgrades would seem to be necessary in the larger scheme of Strategic Reconfiguration a noted discrepancy begins to appear in the record documentation at this point. At some point prior to the commissioning of this study, the Owners chose to disregard the suggested plans for improving communication systems and SCADA controls as studied in The Bailey Report (ATC-102) in favor of full automation and remote control as suggested in this conceptual engineering reports. As discussed earlier, The Bailey Report examined six options for updating and modernizing the telecommunications infrastructure and SCADA of TAPS. The Bailey Report recommended Alternative D which contemplated that the pump station would be manned 24 hours a day, but, the staff would focus on maintenance rather than operating functions (*see* ATC-102:23). In the Bailey Report, Alternative F contemplates fully automated pump stations with additional scoping requirements (as compared to Alternative D) which would include, but was not limited to: Replacement of manual valves with actuated valves, additional turbine fuel measurements and a significant increase in the number of instruments required (ATC-102:24).

310. ATC-751 contemplates replacement of manual valves with actuated valves: "The vendor shall review the existing fuel system to recommend and supply new fuel control valves. Preference shall be given to using DC powered electric valves" (ATC-751 at 46). Also contemplated in ATC-751 are additional turbine fuel measurement devices (for one example *see* section 3.6.4, Ex. ATC-751 at 32) as well as a significant increase in the number of sensors and measuring devices. The Control and Business System Upgrades

[239] *See* Exs. SOA-178 and ATC-808 at 12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Conceptual Engineering Report (Exhibit ATC-751) describes a control philosophy that closely compares, if not identical, to Alternative F described in the Bailey Report. The recommendations in ATC-751 are not compatible with the control philosophy espoused in the Bailey Report or Alternative "D." Additionally, Exhibit ATC-752 has no indication that the control philosophy discussed and recommended in The Bailey Report is being implemented.

311. How the owners transitioned from the well-studied and economically justified Alternative "D," as described in The Bailey Report, to the discarded and economically inferior Alternative "F" scheme (which requires no personnel present at remote pump stations for operations) is not explained nor is there any record evidence to support deviating from the recommended course of action in The Bailey Report. As discussed earlier, The Bailey Report was produced in 1997 and reviewed in 1999. The outcome of the 1999 review essentially supported the conclusions in the Bailey Report. Yet by January 19, 2001 it can be shown through a careful examination of the record evidence in this case that the economically superior control scheme, Alternative "D" (as described in The Bailey Report), was cast aside with little or no justification to support a shift in control strategies to a fully automated control scheme previously contemplated and deemed inferior in economic terms.

Owners Meeting October 2001

312. In an October 17, 2001, TAPS Owners Meeting at Fairbanks Alaska the following strategies were discussed from a TAPS Strategic Planning Team paper: Ex. ATC-135 at 14-18.

NORTH SLOPE STORAGE

Description
Use significant additional tank storage at the North Slope to substantially reduce the pipeline operation' and facilitate some reductions at the terminal. Drive overall reductions in the TAPS operation with the substantial pipeline activity reductions.
Rationale
Addition of tank storage at the North Slope and elimination of pipeline pump station staffing and change in maintenance deployment will, taken together with facilitating changes in spill response and other impacts on pipeline, support, terminal and tankers, result in a higher value Alaska oil business. Tank storage at the North Slope will add capacitance in the system at the best location (near production, the primary system bottleneck) allowing cost reductions in operating the pipeline system. The underlying driver is that significant operating costs for the pipeline are incurred to maintain a high pipeline service factor and that these costs can be significantly reduced

20140227-3052 FERC PDF (Unofficial) 02/27/2014

and, even with the cost of addition of significant storage at the NS, value is created. Also, by adding capacitance to the total system the addition of storage at the NS reduces the impacts of berth 3 removal and eventual elimination of ballast water treatment to the extent these actions add value to the Alaska oil business. Further, addition of storage on the NS in the near term may facilitate future elimination of some storage at the Terminal and might impact (at the margin) the capitalization of the tanker fleet in the Alaska business.

Major Uncertainties

- The frequency and duration of unplanned pipeline events with no pump station manning.
- Response and repair times for unplanned pipeline events and the maximum duration of an extreme pipeline event with maint center in Fbks (maintenance response from only Fbks), increased use of central maint. personnel.
- Pipeline operations and maintenance headcount with no pump station manning, pump station auto/control for unmanning, single maint facility, flexibility of scheduling shutdowns. Pipeline Civil/ROW unit cost with reduced pump station operations and maintenance staffing and related infrastructure.
- Pipeline OSCP headcount & equipment necessary to obtain agency support of spill response from regional bases.
- Alyeska support organizations headcount with the change in strategy (e.g. elimination of PS staffing, flexibility with tank storage).
- Installed cost of storage, additional operating, maintenance personnel and contractor personnel, services and equipment for the storage facility.
- Operational impacts on NS producers of potentially more frequent TAPS prorations or possibilities of prorations, long term revenue impacts of TAPS prorations ("cost of deferred production").
- Commercial arrangement for North Slope storage, tariff recovery of storage costs.
- Impact on prorations/tanker operations of taking berth 3 out of service in context of additional storage at the NS.
- Future quantity of unsegregated ballast water on tankers calling on the Terminal. Extent of impact on revenues, tanker operations/costs of eliminating BWT.

Strengths	**Weaknesses**
- Storage is a certain method of providing system service factor in concert with significant excess pipeline rate capacity. - Storage will allow more frequent and longer duration pipeline stoppages for regular maintenance. Requirements and costs to orchestrate multiple work items are significantly reduced. Demands on limited skilled labor force can be spread. Time pressures are significantly reduced.	- High initial cost of adding storage. - Pipeline manning reductions on the line may shift costs to other areas but not necessarily reduce them. - Adding tanks at the NS will cause operating and maintenance costs for the additional facilities. - Limited successful experience with large tank installations on the NS. Kuparuk divert tanks are relatively small and have

20140227-3052 FERC PDF (Unofficial) 02/27/2014

- Storage will facilitate line stoppages to check for suspected problems with significantly lowered time pressure and concerns for prorations and related impacts. - Storage provides a tangible symbol of investment to facilitate cost reductions, both direct and indirect. - TAPS system will become physically more similar to other pipeline/terminal systems. - Commercial flexibility. Storage may not fall under TSM or TAPS Op Agmt.	had problems. - Increase, for limited periods, in above ground physical inventory in the TAPS/Alaska oil delivery system subject to accidental release. - Pipeline operational issues that may result from more frequent stops/starts of the line. - No agreed commercial or State terms.

THE MINIMUM

Description
As personnel make up potentially 60% of the total costs of running TAPS, this strategy aims at reducing activity everywhere, minimizing manning levels everywhere, minimize the equipment resources everywhere, and making the minimum investments necessary to facilitate this approach.
Rationale
Focus is on reducing costs at all possible opportunities. The goal is to reduce everything we do to the minimum, take potential cost savings as they present themselves like minimal manning, and urban schedules. A lower cost operation would result in a lower service factor but this would be offset by selected investments to bring service factor levels back to an acceptable level.
Major Uncertainties
- The frequency and duration of unplanned pipeline events with minimal manning. - Response and repair times for unplanned pipeline events and the maximum duration of an extreme pipeline event with regional maint. centers (maintenance response from only the five bases), increased use of central maint. personnel. - Pipeline and VMT operations and maintenance head count with minimal pump station manning, reduced operated tanks at Valdez, reduction in power/vapor operation and other operations with reduced terminal tank storage. - Pipeline OSCP headcount & equipment necessary to obtain agency support of spill response from regional bases. - Alyeska support organizations headcount with the change in strategy (e.g. minimal PS staffing, significant reduction in Valdez operation). - Up-front costs to remove terminal tanks from operation, addition of 2 of 3 vapor handling to Berth 3. - Operational impacts on NS producers of potentially more frequent TAPS prorations or

20140227-3052 FERC PDF (Unofficial) 02/27/2014

possibilities of prorations, long term revenue impacts of TAPS prorations ("cost of deferred production"). - Impact on prorations/tanker operations of taking nominal 6 **MM** barrels storage out of operation offset by berth 3 vapor flexibility. - Future quantity of unsegregated ballast water on tankers calling on the Terminal. Extent of impact on revenues, tanker operations/costs of eliminating BWT.

Strengths	**Weaknesses**
- Minimal capital demands - Straight forward to implement - Limited demand on organization, no new skills required - Reducing costs ultimately makes the business stronger - Create a new culture of keeping costs under control	- Potential public opinion and regulator acceptance - Potential increased security risk - Potential labor issues - Possibly disruptive to producers, marine, marketing operations - Loss of operational flexibility - Loss of options

MIDDLE SIZED STEP

Description
Make a moderate investment to obtain the bulk of the reduction of operating and maintenance costs while still maintaining the pipeline service factor at acceptably high levels
Rationale
The reduction in throughput has allowed us the opportunity to change the mode of pipeline operation and maintenance from rapid response reaction for maintaining service factor to utilizing redundancy of equipment and planned response to maintain service factor. The excess capacity of the pipeline provides additional time for response prior to an impact on the producers. Staffing and facilities that were necessary to support rapid response can be reduced and co-located with other pipeline functions. The removal of personnel living onsite at remote facilities allows for a reduction in equipment and systems installed to provide for personnel support. This combined with the removal of excess process equipment and facilities from service, reduces the amount of maintenance required. Control and monitoring systems can be upgraded at a sufficiently low cost to allow the facilities to operate with acceptable risk with minimal manning. The reduction in manning will reduce the need for a significant recruitment and training effort to replace retiring personnel. The underlying driver is that with a low to moderate capital investment, operating costs can be reduced and taken together with an expected minimal reduction in pipeline service we can add value. Furthermore, greater reductions in operating costs will either not add value because the combination of capital cost and service factor impacts do not add value

20140227-3052 FERC PDF (Unofficial) 02/27/2014

or present unacceptable risk.

Major Uncertainties

- The frequency and duration of unplanned pipeline events with minimal manning.
- Response and repair times for unplanned pipeline events and the maximum duration of an extreme pipeline event with regional maint. centers (maintenance response from only the five bases), increased use of central maint. personnel.
- Pipeline OSCP headcount & equipment necessary to obtain agency support of spill response from regional bases.
- Pipeline and VMT operations and maintenance headcount with minimal pump station manning, pump station auto/control for unmanning, VMT control room consolidation.
- Headcount and unit cost for pipeline ops and maintenance and VMT maint. as a result of from the change from field to urban schedules.
- Pipeline Civil/ROW unit cost with reduced pump station operations and maintenance staffing and related infrastructure.
- Alyeska support organizations headcount with the change in strategy (e.g. reduction in field assigned personnel).

Strengths	**Weaknesses**
- Incremental approach provides for validation of investment return and pipeline service factor without full investment. - Allows service factor risks to be quantified with respect to reduced manning - Provides significant return early. - Provides sufficient time to coordinate personnel changes with anticipated attrition issues. - Provides capital investments in the pipeline infrastructure demonstrating a commitment to the future operation of TAPS and facilitates future operating cost reductions. - Reduces support infrastructure such as training, provides greater consistency in maintenance, reduces organizational barriers.	- Moderate costs incurred in station reconfiguration and automation - The significant portion of the savings is in personnel reductions and shift/location modifications that requires a personnel management plan tailored for this effort and effective implementation of that plan. - Requires several years of transition. Therefore, the commitment to the plan must be able to weather changes in Owner and Alyeska management personnel. - Requires an organization wide paradigm shift from *24/7* field based operations response to spare utilization with response coming from off-site. - Requires agency approval of regionally based response for oil spills

RE-INVESTMENT

Description

Maintain a high service factor while reducing on-going operating and maintenance costs by increasing up-front investment costs in TAPS.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Rationale The focus of this strategy is to increase up-front investment in order to realize greater than offsetting savings in pipeline and VMT operation and maintenance costs as well as significantly reduced costs in support functions while maintaining a high service factor.
Major Uncertainties - The frequency and duration of unplanned pipeline events with no pump station manning with new equipment and automation/controls. - Response and repair times for unplanned pipeline events and the maximum duration of an extreme pipeline event with maint center in Fbks (maintenance·response from only Fbks), increased use of central maint. personnel and new equipment and remote sensing. - Pipeline OSCP headcount & equipment necessary to obtain agency support of spill response from regional bases with additional detection/prevention. - Pipeline and VMT operations and maintenance headcount with no pump station manning, new equipment, single control room consolidation. - Headcount and unit cost for pipeline ops and maintenance and VMT maint. as a result of from the change from field to urban schedules, new skills req'd. - Pipeline Civil/ROW unit cost with reduced pump station operations and maintenance staffing and related infrastructure, new equipment. - Alyeska support organizations headcount with the change in strategy (e.g. reduction in field assigned personnel). Utility supplied power costs, commercial arrangement. Cost to implement the "electrified, automated" pump stations, changes to OSCP. Tariff recovery of investments. - Long term revenue impacts of TAPS prorations ("cost of deferred production").

Strengths	**Weaknesses**
• Significant reduction in operating, maintenance and support costs and associated headcount • No requirement for additional storage tanks • Minimal impact on service factor	• Requires significant up-front investment in order to obtain projected savings • Larger incremental change from status quo, and thus, higher uncertainty associated with projected costs, savings and service factor • Requires agency approvals for the revised OSCP

INERTIA

Description
Move forward with minimum apparent operational risk. Continue to operate the pipeline

20140227-3052 FERC PDF (Unofficial) 02/27/2014

<table>
<tr><td colspan="2">and terminal in essentially the same manner as we do now.</td></tr>
<tr><td colspan="2">Rationale

The current system has evolved to provide the highest value, with some limited incremental changes. While significant improvements in the implementation of the status quo strategy are possible, they should be pursued in the context of the existing base system.

The underlying drivers are that capital costs to change will be high enough that operating cost reductions will not result in added value and that a value adding tradeoff between operating cost and service factor is not available.</td></tr>
<tr><td colspan="2">Major Uncertainties

- Alyeska support organizations headcount.
- Pipeline and VMT operations and maintenance unit costs, especially ability and impacts of maintaining staffing levels in light of significant personnel retirements in the near future, minimal changes to equipment on the pipeline and in the terminal.
- The frequency and duration of unplanned pipeline events with current operations.
- Response and repair times for unplanned pipeline events and the maximum duration of an extreme pipeline event with current operations.</td></tr>
<tr><td>Strengths

- Minimal risk in context of catastrophic event.
- Low capital requirement.
- Limited disruption, stable base for incremental operational management improvements.
- Minimal uncertainty to producers and markets.
- Maintain flexibility to change in the future.</td><td>Weaknesses

- Limited visible commitment to change, no physical symbol. Does not provide catalyst for improvement.
- Ability to replace aging workforce.</td></tr>
</table>

313. Another chart in this exhibit lists the following for the reinvestment strategy: un-man all PS's except PS1 (minimal PS 1 manning); install "Electric Drives" and purchase commercial power where feasible; full automate operations with Remote Sensing for maintenance, regional response personnel/equip at maint centers, employ additional detection/prevention. Negotiate for prevention/detection credits to offset response requirements, centralized control of pipeline at various locations. This strategy would have a centralized control for the pipeline and the terminal in multiple locations (Valdez, Anchorage plus possibly Fairbanks at PS1). Ex ATC-135 at 21.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

314. Inertia required fully manned operations full time, super pumps at PS 3 and 4 by 2003 with 2 pump configuration and minimize PS 12, maintain existing automation with critical upgrades only, maintenance at each PS plus Fairbanks and Valdez. Ex. ATC-135 at 19.

315. The middle sized step entailed minimal manning at PS 3, 7, 9, and 12, minimize PS 12, super pumps at PS 3 and 4 in 2003, "2 pump config," and enhanced automation and controls for unmanned operations. Ex. ATC-135 at 22.

316. The minimum strategy required minimal operational manning of all stations (nominally 2-4), outsource non-core activities, minimize PS 12, super pumps at PS 3 and 4 in 2003, "2 pump config" and maintain existing automation with critical upgrades only. Ex. ATC-135 at 23.

317. NS Storage would also un-man all PS except PS1, minimize PS 12, super pumps at PS 3, 4 and 2 pump configuration, enhanced automation and controls for unmanned operations, regional response personnel/equipment at maintenance centers, maintenance at Fairbanks, the control rooms would remain as they were with minimal critical upgrades. *Id.* at 20.

318. As can be seen there are commonalities to some strategies. The strategy not selected was "Pure Automation." Ex. ATC-135 at 25. Note that the only strategy that discussed electrification was the reinvestment strategy. Further evaluation was going to create a range of ongoing costs cash flows by year for each strategy. From the cash flows an NPV analysis can be done by each Owner company using their own discounted rates. Ex. ATC-135 at 32. Additionally, further studies would create a range of costs for the investment required for each strategy. *Id.*at 33.[240]

319. The NS Storage and Reinvestment strategies both unmanned all PS's except PS 1 (minimal manning), regional response personnel and maintenance at Fairbanks. However, only Re-Investment required full automation, NS storage required enhanced automation and controls for unmanned operations. NS storage required lower skilled lower paid workforce, whereas Re-Investment required higher skilled, higher paid workforce lower in number. The other difference between the two is that Re-Investment called for a centralized control of pipeline and terminal in multiple locations. *Id.* at 24.

Rabinow testimony on electrification

320. Rabinow (at the time president of ExxonMobil Pipeline Co.) testified that at this time the electrification option was to electrify only at those stations where it would be

[240] Flood testified that this was the result of months of work and feedback from hundreds of Alyeska employees. Tr. 5408:11-25.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

possible to obtain commercial electric power. Ex. ATC-20 at 25:1-5. However, he also testified that he suggested the possibility of electrifying PS 3 and 4 where there was no commercial power. *Id.* at 25:19. At the time, he suggested that electricity could be supplied in various ways: running power from the NS Producers power generation facility at Prudhoe Bay, running power from a potential new generating facility at PS1, or by generating power locally using the natural gas that was already available at those pump stations. *Id.* at 25:19-26:7.

October 26, 2001 email

321. An October 26, 2001, e-mail from G. Pomeroy to J. Riordan sheds light on the alternatives being examined at the time. Pomeroy describes ten components of the various strategic alternatives that will be evaluated to determine the investment cost and range of uncertainties. He states that this is the first pass at describing the scope of the investment to be evaluated. First, for the electrification of PS 1 by generation connected to the North Slope Producers (NSP) Grid, the MLUs and booster pumps and gas compressors at PS 1 will be converted from gas turbine drivers to electric drivers. Power generation at PS 1 will be diminished to provide standby for life-safety, critical controls and communications. No standby power to maintain pumping will be provided. Backup power for operations will be provided by the existing capacity in the NSP grid for generator maintenance. Second, for the electrification of PS 9 by connecting to the GVEA gr*id*, one of the MLUs will be converted to electric drive. The second unit will remain powered by a liquid fuel turbine. Standby power to maintain life safety, critical controls and communications will be provided on site. Pomeroy identifies significant uncertainties, the costs of long term power contracts and the reliability of the power system. Ex. ATC-902 at 1.

322. Third, for the electrification of PS 12 by connecting to Copper Valley grid, only one MLU would be converted to electric drive. All other pump units would be decommissioned. Standby power would be provided on site. Again, Pomeroy points out that there are significant uncertainties related with the cost of power contracts, reliability of the power system, "contract term vs. the need related to throughput projections." *Id.* at 2.

323. Fourth, for the electrification of PS 7 there is one MLU connecting to GVEA grid. All other pump units will be decommissioned, with standby power on site. The significant uncertainties are as described above. *Id.*

324. Fifth, pump stations PS 12, 7, 9 and 3 would be automated to the extent that would allow operation without full time personnel on site (either operations or maintenance). Evaluations will be prepared for each site based on the following equipment configurations: PS 12- single mainline unit, primary commercial power, standby power for life safety, critical controls and communication only. PS7- single mainline unit, primary power generation, standby power for life-safety, critical controls and communication only. PS9-two mainline units, primary power with full standby capacity

20140227-3052 FERC PDF (Unofficial) 02/27/2014

and auto transfer capability. PS3- two mainline units, primary power with full standby capacity and auto transfer capability. *Id.*

325. Sixth, there will be full automation with remote sensing for maintenance. Automation of mainline units, power generation, and other required utilities. Installation of video cameras to allow remote monitoring of each facility. *Id.* The rest of the components deal with adding storage capacity, consolidation of the VMT control room, and centralization of TAPS control rooms in multiple locations. *Id.*

326. Joe Riordan responds to this e-mail on October 26, 2001. He states: "[l]ooks good with the exception that I would not pursue electrifying PS-7 or 12 because their life is limited. Instead, I would look at electrifying PS-3 and 4 using power generation provided by a new source eg. [sic] GE 10 units placed on-site." *Id.*

Email November 2001

327. W. Howitt states in an email to E. Maxwell on November 9, 2001 that during discussion in a meeting they clarified that the current "Reinvestment" strategy is really centered on improvements to optimize the efficiency of the current pump station configuration. "I advocated that another 'Reinvestment' tactic is to use the 'clean sheet' approach which could employ an entirely new pump station." Ex. ATC-137. That meant that the existing pump stations would be replaced with new facilities, "as though the pipeline were being newly constructed." Ex. ATC-19 at 44:2-4. His sense was that the "efficiencies of a clean sheet approach could more than offset the cost of automating the many built-inefficiencies of our pump stations present design." Ex. ATC-137.

Email December 3, 2001

328. A reasonable estimate of the life expectancy of the "Woods" Avon units in operation at this time is 13,000 hours according to an e-mail from Jerry DeHaas to Glen Pomeroy dated December 3, 2001. He states they are hoping to increase the life expectancy to about 25,000 hours. He also estimated the maintenance cost of the Avon units for 2001 at 30/35 dollars per fired hour. Ex. SOA-20. In this e-mail DeHaas describes the pump station Avon units generally in good condition.

Strategic Planning Meeting

329. In a Strategic Planning Team meeting in December 10, 2001, they discussed the five strategies cited above. The North Slope Storage is now named Flywheel, Minimum, Middle-Sized Step, Re-Investment is said to have been modified as follows "now with New Pump Stations" and Inertia. Ex. ATC-138 at 5. The Re-Investment with new pump stations is essentially new electric drive pump stations developed after discussion with Wight, Howitt, Rabinow. The team proposes to replace the previous re-investment strategy. Ex. ATC-138 at 6. The Re-Investment strategy would un-man all pump stations except PS 1, which would retain minimal manning, maintenance would be

20140227-3052 FERC PDF (Unofficial) 02/27/2014

undertaken with an urban schedule (8-5), and minimal manning for seasonal major maintenance, the pump stations would be reconstructed in new modules with electric drives; gen. power or commercial power where feasible, with full automation operations with remote sensing for maintenance, regional response personnel/equipt at maint centers and centralized control of the pipeline. *Id.* at 15-16. Regarding PS 1, a note indicates that it is a constant speed pump being driven by an electric motor.[241]

330. The exhibit on page 9 has a caption "Optimized Base Case/Prize Compression" a concern is described as: "ongoing cost reductions attributed to strategies that can be captured in any, esp. the inertia strategy." It continues by stating, "i.e. perceived prize of any strategy should be "compressed" by the optimization of the base case." *Id.* at 9. This page goes on to indicate that the "Team not unanimous on approach to deal with this, the two sides: Team evaluates "compression size", Leadership team (with possible input from APSC) separately considers "compression size" in selection of best strategy." *Id.*

331. The new investment costs in this document total $75,500 for Re-Investment (draft form). The 10 year major maintenance projects total for Re-Investment is $59,683. It is noted that the total new investment costs seem very low in comparison to the total 10 year maintenance costs in this document.[242] Ex. ATC-138 at 33-42. According to this document the current staff level was 464. Inertia would reduce 77 employees, minimum would result in 165 staff reductions, storage/flywheel would reduce 215, mid-sized would reduce 185 and recapitalization would reduce 270 personnel. *Id.* at 49. Salient in this document is the assumption that the new equipment will incur 50% of the current O&M costs "then the maximum supportable investment is approx. $84M." A handwritten note states "10yr-10% NPV." *Id*. at 25. Note that the document at page 21 states, dealing with Inter-tie to CVEA at a projected $4 million, "Insufficient power generation exists for 8 months of year." The incremental cost of generating power at P/V is $.12/kwh since waste gas use is currently maximized. This approximated the CVEA avoided cost of power. *Id.* at 21. Additionally, the graph for service factor shows that all the other options (excluding Re-Invest) had higher service factors.

December 14, 2001 State Fire Marshall

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[241] It is surmised that variable speed frequency drives are not being considered at this point in time and thus it cannot be concluded that this electrification scheme is identical to the one ultimately adopted.

[242] There are no new investment costs for minimum. However, for PS 1this category has a 10 yr major maintenance projects total of $116,409; Inertia has a total new investment cost of $2000 and $125,609 for total 10 yr major maintenance projects; the middle alternative has a new investment total of $22, 600 and 10 yr major maintenance projects total of $100,812; Flywheel has a total new investment of $127,000 with 10 yr major maintenance projects total of $100,234.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

332. In a white paper dated December 14, 2001, the Carriers report the issues with the fire and gas control systems. The State Fire Marshall gave an order and notice to correct deficiencies to Alyeska in July 2001. The Fire Marshall was requiring Alyeska to replace the existing fire and gas control systems at the pump stations. Ex. SOA-149. The Order required new, approved and listed equipment because "the existing systems has been upgraded, modified, and/or replaced without approval and plan review by the State Fire Marshall." The deadline established for Alyeska to make a commitment to replace the systems and provide an implementation schedule was January 15, 2002. Alyeska would be in compliance if it made a commitment to replace the existing systems and commence a prototype installation at PS 1 in 2002 with a completion schedule by 2004. *Id.*

333. Alyeska proposed a six-step plan to resolve the Fire Marshall concerns. Ex. ATC-137 at 2-3. It also proposed to modify or replace the existing fire and gas detection and suppression systems by December 31, 2005. *Id.* at 3. The cost to modify the systems was $2 million. *Id.* at 1. However as will be shown below replacement would cost up to $20 million.

Single unit operation

334. At this point in time (December 17, 2001) single unit operation and 2-unit operation was being recommended. This was to remove unit number 2 from the three unit operations at PS1, 3, 4, 9 and 12. The removal of pump stations 7 and 12 were being recommended also. Ex. ATC-139.

TAPS Engineering Mannual

335. This record contains a document which defines the mechanics for conceptual, preliminary and final design engineering. PM-2001 dated December 31, 2001, is the TAPS Engineering Manual. It includes an implementation phase. Ex. ATC-140. The stated purpose of the document is to provide direction and guidance to all personnel performing engineering, design, and design-change functions supporting operation, maintenance and modification of TAPS. "The manual presents the processes and systems that meet the requirements of DB-180 Design Basis Update, and the Alyeska Quality Program with its applicable Principal Implementing Procedures (PIPs). Compliance with the processes presented in this manual satisfies the requirements of the Alyeska change management program." Ex. ATC-140 at 35. The document is described as the source manual for engineering activities that support modifications to TAPS. It includes Conceptual Engineering, Preliminary Design and Scope of Work Development, Final Design, Implementation, Transfer of Custody, Care and Control, Turnover, Closeout, Limited Scope Modifications and Standard Design Packages. It incorporates

20140227-3052 FERC PDF (Unofficial) 02/27/2014

all of the requirements for these engineering activities focused on hardware modifications.[243] *Id.*

Discussion 2001

336. The record shows that the Carriers during this time frame were considering upgrading their controls and automation. From 1994-2001 the Carriers engaged in a process to upgrade facilities and achieve cost savings. As shown above, for seven years from 1994-2001 the Carriers engaged in an engineering process to study the ways that TAPS could be upgraded to achieve cost savings by increasing operational efficiencies and reduce staffing. As Sanders testified this process was consistent with industry standards.[244] Ex. SOA-542 at 37-38. The process included experienced Alyeska personnel who had detailed knowledge of the TAPS equipment, it integrated operations staff with industry experts into the process, the technical and cost assumptions were challenged and carefully tested, there was sufficient time to complete the studies, and finally, each study built upon the last (comprehensive investigation of project options). The resounding conclusion of all these studies, as the State points out[245], was that the Carriers could most economically achieve the efficiencies and cost savings they were seeking by automating the existing equipment.

337. The Control and Telecommunication Long Range Plan studied the legacy equipment and recommended control system changes to increase efficiency and reduce costs. Ex. SOA-135 at 16 (the Bailey Report discussing the 1994 study). This same process continued through the Bailey Report (Ex. SOA-135[246]), the Draft Reinvestment

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[243] The evidentiary value of this exhibit is diminished by the fact that there are strikeouts, lines or x's done by hand and hand written notes on the margins of the document which have not been explained on this record. *See* Ex. ATC-140 at 82, 94, 97, 98, 142, 209, 230, 253, 258, 263, 310, 321, 331, 346, 367, 368 and 369. The most peculiar is what is contained on pages 364 through 366 which are pages dealing with "Physical Therapy Corner: Iliotibial Band Friction Syndrome Treatment." Certainly, the decision in this case will not rest on what is contained in these pages since they are totally irrelevant. However, this exhibit calls into question the accuracy and integrity of the documents produced in this proceeding.

[244] D. Sanders has 40 years of experience on oil and gas pipeline engineering issues. Ex. SOA-425 at 14. Additionally, he has extensive experience with the planning and implementation of large scale oil pipeline construction projects. *Id.* He has worked on projects involving upgrading existing oil pipeline facilities and on projects involving upgrades to oil pipeline control systems and automation.

[245] State IB 138.

[246] Discussed in this ID as ATC-102.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Strategy Study (Ex. SOA-143 or ATC-105 supra), VECO's Addendum Report (Ex. SOA-134), the Strategic Breakthrough Report (Ex. ATC-899), the Strategic Initiatives Report (Ex. ATC-108), AFE-180 (Ex. ATC-110), the Kenonic Control Report in 2000 (Exs. SOA-156 or ATC-114) also Exs. ATC-751 and 752 discussed *supra*, and finally Alyeska's progress report (Ex. ATC-119 or SOA-233).

338. The commonality of all of these studies is that they relied on experienced TAPS personnel with knowledge of the operational intricacies of the pipeline and the operations staff was integrated into the process. For instance, the Bailey Report was drafted by a team that included contractors and Alyeska operations personnel with ample experience operating TAPS. The report was reviewed and validated by Alyeska operations. Ex. SOA-135 at 37. The Bailey Report stated that its focus was to bring Operations into the team and decision process. As a result, the report states that "we can deliver a recommendation that is endorsed by operations." *Id.* at 16.

339. The 1999 Reinvestment Strategy Study focused on technical and economic evaluation of facility changes for the purpose of improving efficiency for TAPS. It was a disciplined and systematic approach, the analysis was initiated using Value Engineering Principles from PM 2001, App. 4, Section 8.2 for a recommended decision package. Ex. SOA-143 at 3. Additionally, the Bailey Report staffing levels were validated by the Fairbanks Business Unit Conceptual Engineering group, and these results formed the basis for the rough-order-of-magnitude estimated savings presented in AFE 180. Ex. SOA-153 at 18. Note also that option D from the Bailey Report formed the basis for AFE 180. *Id.* at 19. Kenonic independently examined the project's technical viability and cost projections, internally and externally by sending Requests for Proposals to vendors to obtain competitive bids for the project. *See* Exs. ATC-756 and 757. Consequently, the automation and control upgrades based off the legacy equipment was thoroughly examined and vetted.

340. As the State points out the studies were indeed highly detailed as described above. The scope is well defined down to the components of work at the individual system level. For instance, the Bailey report specifies what needs to be done for each option on a system by system basis, for 24 systems from Enterprise SCADA and Control Room infrastructure to HVAC systems. See Ex. ATC-135 at 41-48. The report also contained a cost breakdown for each system. *Id.* at 40. For example, even for a lower cost item in the recommended option (DRA system Optimization) Bailey specified that 36 transmitters (pressure, Temp & diaphragm seal), 2 actuators, 2 mass flow meters, and 1 rupture disk with fiber optic alarm would be needed to provide monitoring, alarming with remote set-point adjustment, and DRA injection. *Id.* at 47.

341. Moreover, the reports were not rushed, but took ample time to prepare. For instance, Bailey was the result of a multi-year effort from Alyeska operations and contractor personnel. Further, they were working off the 1994 Telecommunications LRP. *Id.* at 11. Kenonic's Control System Strategy Framework study and follow-up took well over a year to complete. See Exs. ATC-114 and ATC-752. Each report built upon the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

knowledge gained from the last study. With each study the scope of work become more definitive and as time passed, Alyeska was able to use value improving processes and technological change to maximize the level of automation and savings. Consequently, by 2000 Alyeska could recommend the regionalization of maintenance and oil spill response since this would be both technically and economically feasible, and could take advantage of staff reductions and O&M savings. It also estimated completion in 3-4 years. Ex. SOA-35. Dr. Sanders testified that the studies had sound

> time-frames for planning, engineering, and implementing the upgrades for the pipeline system that were viable based on information known at the time. Risks were evaluated and a careful program of logical and manageable change to the system was proposed in all cases. Moreover, the conclusions in these studies were in effect validated by the comments of Alyeska's own engineering personnel. The failure to consider these studies as part of the overall analysis of electrification and analyze why entirely different conclusions were reached was not reasonable.

Ex. SOA-542 at 45. This testimony is given significant weight.

342. Howitt testified that up to this point, the previous Alyeska studies had looked into electrifying one or more pumps and this alternative had been rejected as "the economics did not support the changeover to electric power." Ex. ATC-19 at 47. He also testified that in October 2001, the SR PT presented a reinvestment strategy to the Carriers. The strategy was "principally a control systems upgrade and automation proposal . . . that approach centered on automating the then-existing pump station facilities. *Id.* at 43. He also testified that the "pure automation" strategy had not been selected. *Id.* at 25.

343. The Carriers abandoned all of the above without explanation when they changed course and changed to the Clean Sheet approach or electrification in the fall of 2001.[247] As the State points out even the name "Clean Sheet" foreshadows the fact that they were discarding the previous studies. The clean sheet approach assumed the existing configuration did not exist and advocated complete replacement of the legacy equipment with new electrified pumps as though the pipeline was going to be newly constructed.[248]

344. The evidence in this case shows that in October 2001 upon the suggestion of Exxon's President Rabinow the Carriers changed focus and started considering electrification of all pump stations. In November 2001, B. Howitt advocated changing the SR approach from optimizing the existing pumping equipment to the rebuilding of the

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[247] Howitt stated that he met with Dowling of BP and Flood of Conoco and advocated a "clean sheet" approach which could employ an entirely new pump station. Ex. ATC-137.

[248] *See also* Tr. 4600:16-4602:6; Exs. ATC-21 at 11; ATC-19 at 44.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

pump stations and electrification became the focus of all planning efforts. Ex. ATC-2 at 25:17-19. Thus, after seven years of studies the Carriers changed to an Owner driven program of electrification from an operations-led course of automating the reliable existing equipment. Moreover, this ignored the fact that TAPS was not being built new and the complexities of reconfiguring and automating existing facilities.

345. A month later, the Strategic Planning Team claimed that Electrification would have more staffing savings than all other options (inertia, minimum, storage/flywheel, mid-sized). Ex. ATC-138 at 49. There is no support in this record for these numbers nor any comparison of these numbers with the staff savings of previous studies.

346. They also ignored the deliverables of AFE F180 which required review of the past conceptual studies relating to TAPS configuration and/or asset utilization to: a) assess the study assumptions, conclusions, and recommendation to verify current validity. It also required that viable system-wide combinations be identified for the stand alone configuration/asset utilization options based on linkages and interdependencies identified. This work was to include: "a) Re-assessment and validation of all assumptions, conclusions, and recommendations based on identified linkages/interdependencies." Ex. SOA-153 at 15.

347. In addition, the Carriers ignored their own project development guidelines since all the previous studies had rejected electrification of any pump stations.

348. At this point in time there is no economic analysis to justify electrification. The State is correct that the SR SPT did not explain why it was economically feasible to electrify pump stations without a near commercial power source. Especially, in light of the fact that previous studies had rejected electrification of pumps where commercial power was available as uneconomic. See Ex. SOA-143 at 16.

349. Additionally, evidence in this record shows that BP was constructing (and had rejected electric motors) a new 1,000 mile Baku-Tbilisi-Ceyhan Pipeline (BTC) where power was not available at the same time that electrification of TAPS was being considered. Exs. SOA-542 at 33; SOA-601. This contradicts the claim that electrification of pipelines was industry practice. The BTC pipeline is a modern large-diameter pipeline that operates in remote areas with turbine driven pumps and where the design engineers considered and rejected the use of electrified pumps. Ex. SOA-542 at 33-35. Sanders also testified that the BTC opted to install turbine driven pumps due to "the lack of reliable high voltage power supply in the vicinity of the BTC pump stations, the improved fuel efficiency of turbines over electric motor applications, the high reliability of turbines in these applications, and the acceptable emissions from turbine applications to meet World Bank and Kyoto Protocol environmental standards." Ex. 542 at 33:21-34:17. This testimony is given significant weight.[249] Moreover, the Carrier's

[249] The Carriers assert that this testimony undercuts the State's position on staffing for Hybrid. Carriers IB 106-07. However, the State is correct that this mischaracterizes

20140227-3052 FERC PDF (Unofficial) 02/27/2014

own turbine expert, Scott, testified that in current studies of pump drive alternatives for pipelines (Alaska and others), electric motors are not considered in locations where commercial power is not available. Tr. 5597-98:10; 5596:2-7. The unavailability of third party electric power at PS 3 and 4 was never addressed by the Strategic Planning Team.

350. The Carriers knew that any strategy to upgrade the control systems had to be approved by the Fire Marshall. Additionally, they knew that there were opportunities to upgrade the control systems at reasonable costs. The costs of automation had increased to $ 150 million and it had been pointed out that this was a very complex project which would require four to five years to construct with a very high risk of cost escalation if schedule estimates were wrong.

351. The Carriers agreed to upgrade the fire and gas systems to satisfy the order of the State Fire Marshall by December 31, 2005.

Conclusions 2001:

352. The purpose of the reinvestment strategy was to increase up-front investment in order to realize greater than offsetting savings in pipeline and VMT operation and maintenance costs as well as significantly reduced costs in support functions while maintaining a high service factor.[250] Note however, that full automation or the rejected Alternative F from the Bailey Report is also being considered. This record is devoid of any studies at this point in time for electrification of all pump stations. Note that electrification of pump stations where there was a power grid had been previously considered and rejected. There is no indication in this record that there were any studies conducted to contradict this conclusion. Moreover, there are no studies contravening Bailey. The record does not show how the rejected Alternative F from the Bailey Report was established as the lead alternative. The Carriers recognized that if staff could not be significantly reduced "you may want to look at options to upgrade equipment that might be less costly. Ex. SOA-233 at 4. Salient is the fact that the "base case is going to be optimized" and the options "compressed." Thus, the electrification case would be optimized and the other options "compressed." This is not the type of analyses that a rational utility manager makes.

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the testimony. Sanders did not claim BTC was a "model" for TAPS as the Carriers' claim. What Sanders was testifying about is the well-documented decision to use direct drive pumps for BTC's remote pump stations. Moreover, the BTC staffing claims are not given any weight. There is no evidence in this case as to the staffing of the BTC pipeline (that the pumps are allegedly fully manned) or the level of automation of the pump stations and what functions are performed by the personnel at the pump stations.

[250] *See* Ex. ATC-18 at 2:13-15 (J. Ray) (Carriers made the infrastructure investment principally in order to realize substantial cost savings over the next 20 years or more of TAPS operations). Ex. ATC-22 at 14:22-15:2 (Yaege) (primary goal was to reduce the unit cost of crude oil transportation on TAPS).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

353. Sander's testimony that the decision to go with electrification, an option which had been recently considered, studied and rejected, without any due diligence or explanation of why the prior rejection was wrong is contrary to basic industry practice is entitled to significant weight. Ex. SOA-542 at 11:10-12:2. Further, Sander testified that the "1994-2001 studies should have formed the basis of any further planning of a project of this scope and magnitude under reasonable industry practice . . . . The failure to consider these studies as part of the overall analysis of Electrification and analyze why entirely different conclusions were reached was not reasonable." *Id*. at 45:11-22. Again this testimony is given significant weight.

4. What happened in 2002:

354. On February 5, 2002, the Strategic Planning Team had a telephone conference with the Owners. Ex. ATC-141 or SOA-451. A new reinvestment strategy was recommended for the pipeline. The proposal is to reinvest in new electric motor driven pumps stations.[251] Ex. ATC-141 at 3. The new pump station configurations would be electrification with pre-packaged skid mounted units. *Id.* at 17. Further, the recommendation is to have PS1 manned and PS 3, 7, 9 and 12 unmanned. For regional spill response PS4 and 5 would be manned with a single maintenance center at Fairbanks. Ex. ATC-141 at 3. The strategy included a number of changes to infrastructure that would be eliminated with electrification. *Id.* at 17.[252] Regulatory agency approval for a regional spill response plan is necessary for a significantly unmanned infrastructure. *Id.* at 7. The discussion included the fact that substantial costs reductions are available with operational changes with minimal manning or unmanning of PSs 3,7, 9 and 12[253] and "spill response/civil [Right of Way] manning at PS 4 and 5." Ex. ATC-141 at 7.

[251] Howitt confirmed that this was the presentation where the Team recommended "new electric motor driven pump stations." Tr. 6775:14-16.

[252] The document states "Removal of manned support" and lists: buildings and associated fire systems, permanent living quarters, offices, maintenance shops, hall ways, sewage systems, potable water systems, garbage incinerators, life support electrical generation, fewer vehicles and less heavy equipment, less replacement and maintenance costs. *Id.*

[253] The document states that fully manning all operating pump stations does not provide significant service factor benefits. *Id.* at 7. The service factors for all options were 99.8% or better (it is noted that re-investment is one of two lowest). *Id.* at 10. The new plan would have five regional spill response facilities and two living quarters. This streamlined the previous nine pump station based spill response facilities and six living quarters (does not include an additional living quarter for daytime use only). *Id.*at 8.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

355. According to this document with recapitalization the staffing levels at pump stations and ROW maintenance could be reduced from 472 to 232 or a 240 personnel reduction for a saving of $25,042,000. Ex. ATC-141 at 12. The ongoing cost savings for staffing levels shows six strategies: Inertia with 77 staff reductions; minimum with 149 staff reductions; storage/flywheel with 196 reductions; mid-sized with 201 staff reductions; recapitalization with 240 reductions and flywheel (w/o additional storage) with 206 reductions. Note this page does not mention hybrid. It is a table on the next page which mentions "hybrid" with personnel reductions. This exhibit also shows that the projected savings comparing inertia to hybrid is $16 million and the delta from hybrid to reinvestment is $12 million. Ex. ATC-141 at 13 and 14. It is noted that there is no underlying data to support any of these numbers in this exhibit. The exhibit also shows that consideration was given to the fact that significant changes to pipeline configuration or operation should be incorporated in the Right of Way (ROW) process as soon as possible, waiting is not a real option and that this was a significant driver for the decision timing. Ex. ATC-141 at 35.

356. The pump station usage is described in this document as follows: today 50 turbines (8 RR Avons in use, 8 spare; 10 Garretts in use, six spare; five Solars in use, 13 spares). *Id.* at 19. The new turbines would be 5 with six spares for a total of 11. The scheduled contemplated the new equipment (including pump station 1) being in place by 2005 in some cases (PS3 and 4) by the end of the fourth quarter of 2004. *Id.* at 38.

State Fire Marshall

357. In a February 13, 2002, letter from D. Hisey, Chief Operating Officer of to the State Fire Marshal, Alyeska mentions that it is reviewing pump stations and pipeline configuration.[254] This may result in fire and gas control systems being replaced or modified. As a result, the fire marshal agreed that Alyeska should not be forced to replace components of the fire and gas control system this year solely to achieve code compliance. Ex. ATC-142 at 1.

Staffing Realignment

358. One hundred and fifty (150) positions were being eliminated from Alyeska in April 3, 2002. Of these 50 were from Valdez, 60 from Fairbanks and 40 from Anchorage. The reductions focused on administrative, management and support functions and brought the Alyeska headcount to about 900 employees. In addition to

[254] This was in response to the State Fire Marshal's order to replace the fire and gas control systems at the pump stations. The deadline for response by Alyeska was January 2002. Alyeska estimated that addressing certain issues would be in the $2-2.5 mil ROM. The ROM cost for replacement of the existing system is $20 mil. Ex. SOA-149.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

employees, Alyeska was to going to reduce contractor support throughout the organization by about 150 positions. Ex. ATC-143.

Al Bolea encourages electrification

359. On or about the same day (April 3, 2002), Al Bolea, President of BP Pipelines (Alaska) Inc., states that he was very encouraged with electrification, which was going to be designed in 2002. Ex. SOA-179. He further states "also in 2002 modifications in the TAPS asset base will be designed and we will begin to test a new operating model with the regulators. It is premature for me to be specific, but in a nutshell, it involves fewer pump stations, fewer turbines, electrification, and new control systems. These changes will require considerable investment and we (and all the TAPS owners) need to ensure that its economic, . . . Ex. SOA-179. In this e-mail Bolea also notes that in 2002 Alyeska will restructure to centralize functions and reduce staff and core contractors by 300 people.

Award of Conceptual Engineering Studies/Electrification

360. Award of the conceptual engineering studies for the electrification option was given to JTG Technology and Information Systems and GE Industrial Systems as stated in an e-mail dated May 1, 2002. Ex. ATC-144.

Opinion on length of time to electrify

361. An undated document estimates that electrification of the northern pipeline facilities (pump stations 1 through 4) will probably take 3-5 years. At the time of this document, the return on investment for the owners is not known. Ex. SOA-471.[255]

State Fire Marshall

362. The State Fire Marshall by letter dated June 3, 2002, dealing with Comments on Pump Station Fire Code Survey (5/15/02) states that the timeline for correction of fire alarm and fire suppression system code issues outlined in the Hisey letter of February 13, 2002 will not be extended. The State Fire Marshall letter states that by the end of 2005, all pipeline fire and gas systems will comply with current codes. Ex. ATC-145 at 2. This letter also states that after several inspections and a survey, "there can be no question that the Alyeska fire systems do not meet fire code and system standards in every aspect." Ex. ATC-145 at 8.

DeHaas email June 21, 2002

363. In an e-mail dated June 21, 2002, from Jerry DeHaas he mentions that if they need another unit they would not buy a new Avon but a used one which are plentiful.

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[255] The exhibit chronology of the parties dates it to May 13, 2002. Ex. ALJ-2 at 5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

However, they would not need to buy old units since they have several used (not operable) units sitting at a warehouse. He states the Avons are obsolete, and slowly being removed from service, around the world. Concerning the pump rotating elements he states the situation is similar to the Avons but that there are no other pumps around the world like the ones we have; however, we have several used ones that can be used for replacements. Ex. ATC-146.

JTG Report- Electric Drivers

364. Exhibit SOA-158 is titled[256], Engineering Study – Electric Drivers, TAPS Contract #8536, Binder #1 – Study Report, (JTG Report). This report is authored by JTG Technology for Alyeska. This report has no date on the cover page or any of the introductory sections. A date of July 16, 2002, can be observed on page 49 of this report in the section titled, Hydraulic Analysis Variable Speed Pump Operation.[257] This is assumedly the date when the Hydraulic Analysis was completed not when the JTG Report was produced, but for purposes of placing this study in chronological context of the TAPS SR project, this rough date of production is adequate.[258] The Project Schedule Milestones included in the report show the owner evaluation of Electric Driver Study will be done from August to October 2002 which supports a finding that the report was given to the owners sometime in July-August 2002. Ex. SOA-158 at 8. The study looks at the feasibility of replacing the current turbine driven pumps with electric motor driven pumps at pump stations (1, 3, 4, 7, 9 and 12). Ex. SOA-158 at 51. For various assumed flow rates there are various suggested pump configurations. *See, e.g.*, Ex. SOA-158 at 53-54, 67.

365. The JTG Report is a Conceptual Engineering Report. This is acknowledged in the Executive Summary in Section 1 of this report. The objective of this study was to develop a conceptual design and associated cost estimate that minimized: capital costs, operating costs, modular building sizes that allowed adequate room for maintenance. Ex. SOA-158 at 7. It is noted that mitigation of throughput decline on TAPS is not an objective of this report but, throughput decline is repeatedly cited through the Carriers testimo0ny as one principal justification to proceed with SR.

366. The JTG Report included a recommendation to perform a financial evaluation, per Owner return on investment criteria, to justify the project and secure management approval of project investment funds. Also noted in the Executive Summary, JTG encourages Alyeska to "Proceed with the project Design Basis Phase as soon as possible due to the estimated project execution time-frame being in the order of 30 to 36 months."

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[256] Ex. ATC-147 is the same document.

[257] Alyeska supplied hydraulic boundary conditions. Ex. SOA-158 at 51.

[258] Note that the joint chronology lists the date of this report as July 11, 2002. Ex. ALJ-2 at 5. In its intial brief, the State states the report was completed by July 30, 2002.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Ex. SOA-158 at 7. It is noted here that the project execution time-frame of 30 to 36 months is carried over and maintained in future engineering studies completed within SR. Also, it is unclear why the "Owners return on investment criteria" is a material consideration for a Conceptual Engineering document. The project cost for a 1M B/D flows are in the range of $160M to $258M. The cost estimates were geared for off-site construction with roughly 30% being on-site. *See* Ex. SOA-158 at 14. The design basis phase was estimated to start October 2002 with a project in-service date from December 2005 to March 2006. *Id.* at 9. It was recommended that the project be developed as three sub-projects. *Id.* Note that the report states "Gas is basically free on the North Slope." *Id. at* 160.

367. The JTG Report studied the TAPS system for a throughput rate of 1 million barrels of oil per day (MMBPD) to 1.5MMBPD (SOA-158:8). Ex. SOA-158 at 8 and 188. It is noted that this throughput rate studied in the JTG Report is greater than the throughput rate of TAPS circa 2000. As asserted by the Carriers own witness Howitt, "Throughput peaked in 1988 at nearly 2.1 million barrels per day, and has been declining ever since. ***By 2000, average throughput was less than a million barrels per day***, and in 2010, it averaged less than 620,000 barrels per day" (emphasis added, Ex. ATC-19, at 8:5-7). No justification can be found in the JTG Report that supports a design throughput range of 1-1.5 MMBPD. The design throughput studied in the JTG Report is greater than what TAPS own Witness Howitt testified the pipeline throughput was in 2000, two years before the JTG Report was produced. This raises significant questions with the study parameters of the JTG Report. If JTG received the study parameters from Alyeska, why would Alyeska commission a study for new electric pump drivers for throughput levels that are greater than the actual year 2000 throughput? It seems wholly inconsistent with the premise that electrification of the TAPS pumps was necessary to address anticipated future low flow throughput conditions on the pipeline since the Conceptual Engineering Design of the new pump drivers operating point (1 MMBPD) is greater than the contemporaneous throughput experienced in circa 2002. It seems that at this stage of evolution of the TAPS SR Project, the contemplated design of SR parameters is not in harmony with the actual operating conditions of the then (2002) throughput rates.

368. Furthering this cognitive dissonance of the stated intent of SR (with respect to low throughput levels and the justification used to support the necessity of Strategic Reconfiguration) is the stated Design Basis of the Variable Frequency Drivers (VFD) Pump Station Control & Operation in the JTG Report. On page 188 of SOA-158 it is stated that, "The proposed new VFD based pump stations will be built on the existing station sites to accommodate either two or three pumps ***with the intention*** of adding the third & fourth pumps to meet increased capacity requirements at a later date" (emphasis added). It is unclear why JTG is considering throughput rates on TAPS increasing in future years when copious amounts of pre-filed testimony from the Carriers indicate that crude oil throughput rates will decline in future years and, concurrent with the JTG Report study period, crude oil throughput rates are (in 2002) less than the designed parameters used in the JTG Report.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

369. Equally troubling is the complete lack of support in the JTG Report to demonstrate that the VFD – electric motor combination are essential for continuing operations of TAPS in future years so that declining throughput could be accommodated. The stated requirements for the VFD is not declining throughput but, "The VFD is required to allow motor soft starts and speed control. This methodology is modelled [*sic]* after established proven pipeline pumping stations. The installation of the VFD and associated VFD-PLC control equipment will reduce mechanical strain on the motors, allow for precise speed control and will allow Alyeska Pipeline to sequentially start large motors while minimizing voltage flicker" (Ex SOA-158:188). In summary, the Conceptual Engineering Study by JTG for the replacement of the AVON drivers with electrically driven motors, contemplated throughput levels the new electric drivers are designed to operate (1-1.5 MMBPD) above and beyond what is reasonably expected to be the contemporaneous throughput levels that the Carriers own witnesses cite to (less than 1 MMBPD in 2000).

GE Report

370. Exhibit ATC-147 is a Conceptual Design Study for Electric Drivers for Mainline Pumps commissioned by Alyeska and performed by General Electric (GE). This GE Study was completed on July 16, 2002. In the Executive Summary section GE states that, the purpose of this study is to validate a project concept of replacing six gas turbine driven mainline pump stations located on the Trans Alaska Pipeline System with new modularized and automated electric driven pump packages. A resulting project would provide several owner benefits including significantly lower total operating and maintenance costs. Capacities would be optimized for current and projected future pipeline flow rates, old original systems could be retired and replaced with new smaller state of the art designs, and a solid platform for continued safe and reliable pipeline operations in the arctic environment would be in place.Ex. ATC-147 at 16. The study was started in early May 2002 and completed July 17, 2002. *Id.* at 16.

371. Ostensibly, one benefit cited by GE of changing out the existing Avon turbines (and direct drive pumps through a reaction turbine) with new turbines equipped with variable frequency driven electric motors (to power new pumps) would be optimization for current and future pipeline flow rates. Yet in terms of future "low flow" rate and "throughput," this study contains no in-depth analysis of future throughput due to decline in crude production. In terms of throughput, this GE analysis is limited to failure analysis and pipeline operations with one (new electrified) failed MLU (for example see Ex. ATC-147 at 42, second paragraph). This study does not consider low throughput or low-flow conditions anywhere other than in terms of a failure of an electrified MLU. There is no indication of how, or even if, the proposed design of the electrified MLUs is in any way beneficial in low flow or low throughput conditions expected in future years. In fact, an electronic search of the word "throughput" turns up only one instance of it in this 398 page document. Ex. ATC-147 at 22.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

372. Additionally, an electronic search of the phrase "low flow" shows one instance of the use of that term. Ex. ATC-147 at 55. The lack of consideration of declining throughput (or low flow rates) can be placed in context of this Conceptual Engineering Report when GE made this following statement: It was considered unnecessary by Alyeska for the GE team to spend large amounts of time analyzing their pipeline and trying to understand the actual complexity of the existing pipeline. Rather, we were instructed to spend our efforts analyzing performance of pumps, drives and power generation with this steady-state model defining interface parameters between pumps and pipeline. Ex. ATC-147 at 19. That is, it seems that Alyeska told GE to study the MLU replacement in a static environment eliminating variables, such as declining throughput. Thus, this report has no indications that the proposed electrically driven MLUs were better suited for low flow conditions than existing MLUs because these conditions were not studied here.

373. At the time this GE study was commissioned, Alyeska was aware of declining throughputs. It is curious why Alyeska contracted GE to study a throughput rate for the proposed electrified MLUs that is greater than 2002 production levels testified to in Witness Howitt's pre-filed Testimony: "Throughput peaked in 1988 at nearly 2.1 million barrels per day, and has been declining ever since. ***By 2000, average throughput was less than a million barrels per day***, and in 2010, it averaged less than 620,000 barrels per day" (emphasis added, Ex. ATC-19, at 8: 5-7). Why the GE study considered throughput rates of 1-1.5 MMBPD is unclear. The first bullet point on page 22 refers to "GE was instructed . . . , but to work to [Maximum Allowable Operating Head (MAOH)][259] for the pipeline and identify what is required in pump design to have capacity for 1.5-MMBPD at the MAOH limits." Ex. ATC-147 at 22.

374. Tangentially related to benefit claims made by GE in the introductory section of this report on electrifying MLUs is the then current (circa 2002) ability of the Avon turbines to operate in a variable speed mode. Interestingly the GE report contends that the existing MLUs are capable of variable speed operation. GE states (on page 22 of ATC-147) "Gas-turbine mechanical drive pumps. Pumps currently operate in variable-speed mode and therefore such operation does not represent a change in operating conditions for the revised design basis." Either GE, one of the preeminent manufactures of gas turbines in the world, is mistaken about the possibility of variable speed operation of the Avon's (that is the Avon's are capable of variable speed operations) or the Carriers are wrong about the inability of the Avon's to achieve variable speed operation. It seems that this Conceptual Engineering Report raises more questions than it answers. Additionally, the report notes that "Alyeska experience with existing pumps has been

[259] *Id.* at 24. They were also instructed not to consider the effects of DRA. *Id.* at 22.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

excellent. They have experienced high efficiency with little decline during the past 25 years. The pumps are rugged and durable." *Id.* at 22.

375. The study states among other Alyeska objectives: to modernize and upgrade equipment (replace 25 year old equipment with new equipment of a modern design; operate pipeline from a central location (unattended pump stations). Ex. ATC-147 at 22. In reviewing the design of the existing pumps GE states that the existing pumps efficiency is "reportedly much higher in efficiency than the chart shows and therefore they are "Off the Chart." *Id.* at 23. The generator solution chosen for PS 1, 3 and 4 had $1.7 MM maintenance costs per year. *Id.* at 158. For PSs 7, 9 and 12 the maintenance costs per year are $2.254 MM. *Id.* at 163.

Minimum Pump Station Footprint Study

376. This study dated July 26, 2002, recommended that the stations be simplified to an optimum configuration. Ex. ATC-901.[260] One of the key assumptions was that the pump stations would not be manned continuously and any personnel needed to work with it could live offsite. The estimate for this was $60.2 million. The study compared a new pump station (demo existing facilities and replace w/new pump station design) the estimated cost was $98.6 million plus the costs of demolition of the current facilities. The new pump station design assumed a current pump station was lost due to a catastrophe and new replacement pump station would require to minimize operation and maintenance expense by leveraging current efficiencies in pumps/drivers, control systems, modular construction, piling foundations, remote operations, absolute minimum footprint. *Id.* at 2. Note that this study did not contain an economic evaluation and states that the evaluation of possibilities is ongoing with the SR Team. *Id.* at 3.

E-mails from Jerry DeHaas W. Howitt pointing out negatives of SR

377. Various e-mails from Jerry DeHaas to W. Howitt show his opinion concerning reconfiguration. First, he states that it will come with negatives. (E-mail dated August 8, 2002). Second, considering the fuel savings of new units *vis a vis* maintenance of the Avons he states: "I have rarely encountered the case where the incremental fuel savings justified the CAPEX of higher efficiency replacement packages, and I do have some experience in trying to come up with such justification. Ex. ATC-149 at 1 (same at Ex. SOA-19). In another e-mail on the same day he states that the maintenance costs of the Avons have come down and will settle around $20 to $25 dollars per fired hour, there are ample spare units which we can use to our advantage (zero costs parts) and could even reduce the costs further from the cited $20 to $25 and there are no obsolescence issues with the Avon. "It will continue to be serviceable for many years into the future." *Id.*

[260] It states that the original pump stations were designed to operate unmanned but the original living quarters could accommodate 8 people, four on days and four on nights. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

378. The costs of maintaining the Cooper RTs is minimal ($1 to $2/operational hour). There are no obsolescence issue for these units. Further, he states "these units are essentially infinite life machines. "On a fairly infrequent basis we have to pull a rotor to replace a shaft seal or some other part, but the expenditure(s) is usually minimal. This also infers that the reliability of the present RT is superb, and that it would be difficult to make any gains via installation of new equipment." *Id.* at 2. Additionally, DeHaas states that there are ample parts for the RTs and the same is applicable to the MLU pumps. "We rarely have to remove pump rotating elements. Seal replacements likewise are quite rare. The only ones since I've been here were related to human error." *Id.* The yearly maintenance costs are probably on the order of one or two dollars per operating hour. "The pumps are essentially infinite life, there are no obsolescence issues, and we have a generous supply of parts in inventory. It is a little doubtful in my opinion that replacement pumps would be as robust and reliable as the present units. It would certainly be difficult for them to be any better." *Id.* DeHaas goes on to opine that the maintenance costs of new equipment, of similar design and size would be higher than the present and this amount may be substantial. Further, he states that installation of new low NoX turbines would reduce reliability. *Id.*

379. DeHaas questioned the use of new equipment. He states as follows: "Why doesn't everyone try to install old Avon's and Cooper RT's or equivalents? The answer is two-fold. One an old Avon is not low NoX, and new or modified installations usually require use of low NoX turbines. The second part is related to fuel consumption. The Avon is not bad in regard to efficiency, but certainly not as good as new units. The comparison is roughly 25% for the Avon to 38% for a new unit. Fuel costs on these larger units, if accounted for, usually outweigh maintenance costs by a substantial amount. That being said, I have rarely encountered the case where the incremental fuel savings justified the CAPEX of higher efficiency replacement packages, and I do have some experience in trying to come up with such justification. *Id.* at 1.

Owners meeting August 2002

380. On August 14, 2002 there is an Owners Committee meeting in Valdez, Alaska. At this point in time the Owners are asserting that the comparative net investment for new pump stations has increased approximately $40 million since February. Numbers in this exhibit show Inertia as $120 million Total ($120 million Major Maintenance, $2 Million New Investment). The Reinvestment to existing pump stations would be $120 million ($100 million major maintenance and $20 million new investment). Reinvestment for new pump stations would be $190 ($20 million major maintenance, $170 million new investment). Ex. ATC-150 at 5.

381. The choice is characterized as remaining between Reinvestment in New Pump stations versus reinvestment in existing pump stations. "Higher new pump station capital costs make improved definition of ongoing cost reductions, avoided major maintenance key to the decision. Ex. ATC 150 at 6. Thusly, the new pump station concept was said to remain promising but not ripe for decision. Avoided major maintenance needed

20140227-3052 FERC PDF (Unofficial) 02/27/2014

further scope definition and the regional spill response is necessary for significant changes. The evaluation is to be expanded to reduce capacities and associated changes in investment, avoidable major maintenance and ongoing costs without pump stations 12 and 7. *Id.* The benefits of the new pump station case erode with significant delay in implementation decision (minimal until January 2003, then step change increase due to fire system work). Ex. ATC-150 at 8. The idea is to begin preliminary engineering as soon as possible to preserve fast implementation. A complete proposal with scope cost will be prepared for the Owners by September 16. Ex. ATC-150 at 9. Alyeska is to develop ongoing cost and avoidable major maintenance estimates through long ran planning. Ex. ATC-150 at 10. The aggressive plan is to deliver a quality decision by mid-October. *Id.* at 8. Note that the document states that they are still discussing with the utilities for station power. *Id.* at 2.

382. In an Owners meeting on August 14, 2002, Alyeska's performance was discussed including resolution of longstanding issues and reducing costs of delivering its services. Ex. ATC-151 at 2. The minutes from this meeting state that PS 12 is currently being bypassed based upon the latest throughput activity. Ex. ATC-151 at 3. The Long Range Plan is to be used as a benchmark for future costs and for deciding on strategic reconfiguration. *Id.* at 4. The minutes discuss the fact that Alyeska received the GE and JTG study results and met with GVEA regarding power supply for pumps 7 and 9. It goes on to state that Alyeska is continuing to evaluate the feasibility of early rampdown of PS7 and 12. The minutes state that Alyeska will analyze various approaches for strategic reconfiguration including the assumption of new pump stations being constructed versus no new pump stations. "Alyeska will deliver an evaluation to the Owners by mid-October, 2002, suitable for decision and funding sanction regarding building new pump stations versus modifying existing ones, for preliminary engineering work in the event that construction of new pump stations is recommended. The Owners want a firm estimate on the cost of preliminary engineering work. The Owners also want the evaluation to establish a date during 2Q-3Q of 2003 for sanctioning a full funding cost estimate for strategic reconfiguration." *Id*. at 5.

AMS-003

383. Alyeska Management System, document number AMS-003 is a document that defines what is expected and how to organize work needed to implement a project from conception to completion. AMS-003 revision 0 has an effective date of August 26, 2002, is Exhibit ATC-808.[261] Other versions of AMS-003 appear in this record and are revisions to the initial version (*see* Exhibit SOA-193 and SOA-311)[262]. ASM-003 is

[261] The predecessor to this document included is this record is a 2001 version of the TAPS Engineering Manual. Ex. SOA-178.

[262] Ex. SOA-193 revised section 8.3.1 and Ex. SOA-311 was a substantial rewrite to implement IPA's suggested best practices as demonstrated in Ex. AT-273.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

examined here to garner a better understanding of what was understood when two crucial terms are used by the parties of this instant case. Ex. ATC-808 or ASM-003 is used to better understand what the parties understood when they used the terms "Conceptual Engineering" and "Preliminary Engineering." Revision 0 of AMS-003 is used (Ex. ATC-808) since its effective date of August 26, 2002 is closest to the production date of certain documents that are discussed in this section. Thus, it is reasonable to use AMS-003, revision 0, to place into context the status of SR project pieces and thus understand what state of project completion each document represents at this point in time.

384. AMS-003 is a document which describes the Project Management Process. These are the specific activities and deliverables at each phase of project management. Generally, ASM-003 identifies five (5) phases of a project: Identification, Evaluation, Planning and Development, Implementation, and Completion. Each phase identifies Key Deliverables and Activities and Processes. The first three phases end with a Gate, where a Review Board makes decisions to endorse or reject the process. Ex. ATC-808 at 7.[263] The Evaluation Phase in AMS-003 is used to get an understanding of Conceptual and Preliminary Engineering. AMS-003 (Exhibit ATC-808) does not utilize the exact terms 'conceptual engineering' or 'preliminary engineering' but instead refer to "Conceptual Study" and "Preliminary Development" (see ATC-808:3, 10-13). These nomenclature discrepancies are, at worst, inconsistencies between diverse litigants utilizing slightly different words to describe similar things. In any event, the use of AMS-003 here is to best understand the state of SR at any given time and to identify what phase of the project any one study (or report) could be said to represent.

385. The Evaluation stage is recognized by Alyeska as "one of the most important steps in the project sequence" (ATC-808:10). [264] Also stated here is that the evaluation phase allows for the analysis, evaluation, and comparison of various alternatives to determine an optimal solution. The overall influence of the Evaluation Phase is probably the most important phase of project management since this phase has the greatest ability to influence the cost, safety and quality of a project. Identified as key deliverables for the Evaluation Phase are (but not limited to): Risk Assessments, Feasibility Studies, Analysis of alternatives, Conceptual Studies, Risks to be managed, Business Case and, Preliminary Engineering. Clearly this section of ASM-003 (ATC-808:10) contemplates the production of both "Conceptual Studies" and "Preliminary Engineering" as deliverables for the Evaluation Phase of a project.[265]

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[263] *See also* Ex. SOA-1 at 133:13-14 and 132:15-33:12.

[264] *See also* Ex. SOA-193 at 10.

[265] *See also* Ex. SOA-1 at 137:10-12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

386. A Conceptual Study may be initiated if, ". . . the solution requires a complex economic justification, multiple compelling solutions appear viable and the most practical and cost effective solution is not immediately obvious." Ex. ATC-808 at 12. According to AMS-003, a Conceptual Study need not precede Preliminary Development if the desired solution is apparent (*see* ATC-808:12).

387. Preliminary Development occurs after a Conceptual Study has been approved or without a Conceptual Study if the desired solution is apparent. Key deliverables from Preliminary Development include, but are not limited to: Detailed Scope of Work, Project Design Basis, Statement of project requirements, Turnover deliverables required, Detailed Class III schedule for project, Class II estimate for design when applicable, Preliminary Design Documents, Risks to be managed, Long lead materials identified and, a List of affected documents and training courses.

388. Ex. ATC-808 categorizes project estimates into four types with a list of the Estimate Description and Range of Accuracy. There are four (4) Estimate descriptions, they are: Rough Order of Magnitude has an accuracy range of +100/-50%, Class III Preliminary has an accuracy range of +/-30%, Class II Control (accuracy required for AFE) has an accuracy range of +/-15% and, a Class I Definitive has an accuracy range of +/-10%. As the project moves from phase to phase the estimates increase in detail, accuracy and contingency. This exhibits states that these estimates should be standard with respect to the Alyeska Code of Accounts. Ex. ATC-808 at 13. According to the process the standardization facilitates identification of changes as the project progresses. *Id.* Further analysis of the exhibit indicates that during the Evaluation Phase at preliminary engineering a Class III estimate is needed for costs and this is a Gate 2 review. Ex. ATC-808 at 13-14. At the planning phase a Class II Estimate for total installed costs is needed. Ex. ATC-808 at 16. Long Lead Material Procurement can be authorized at Gate 2. *Id.*

389. Thus, for purposes of consistency in this Initial Decision a judgment will be made with respect to engineering analyses concerning the state of a given study at a specific time. That is, based on the information contained in a study and comparing that information to the definitions contained in ASM-003 (as discussed above) a determination will be made as to whether that study will be considered a Conceptual Engineering document or a Preliminary Engineering document. Utilizing the information contemporaneous with the early years of SR a consistent classification of engineering progress can be culled from the record which will show where in the Project Management Process each document lies so that a fair comparison can be made.

AFE F370- Strategic Reconfiguration, SCADA Host/Historian Replacement

390. This September 30, 2002, AFE F370 requested approval of $8.4 million ($8,350,000 capital/$50,000 retirement) to replace the OCC Supervisory Control and

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Data Acquisition (SCADA) Host System. This was deemed to be necessary for operational integrity of the pipeline. The document states that replacement of the SCADA host will provide a portion of the infrastructure that is necessary for enhanced facility automation that will enable significant reductions of future O&M costs. This funding is a line item under SR and managed within the 2002 Alyeska budget. Ex. ATC-152. According to the document Alyeska will fund the 2002, $500,000 capital for the project by decreasing the current approved 2002 budget of F-180, TAPS SR program. "Project F-180 was originally approved for a 2002 budget of $3,500,000. *Id.* at 3. The project will take three years to implement. *Id.* at 12. Replacement of the SCADA system reduces O&M by one hundred million dollars. *Id.* at 14. The replacement of SCADA with other initiatives will allow for the simplification of systems, automation of monitoring and an overall reduction in staffing of remote facilities. *Id.* at 14. Replacement of the existing SCADA Host system has a direct linkage to cost avoidance through maintaining real time control system availability and pipeline availability at high levels. The cost avoidance is dependent on efficient, operable, and reliable real time control system. The new SCADA will reduce the need for field based monitoring by the ability to monitor real time data and trend historical data from the data historian. *Id.*at 14.

Email October 1, 2002

391. In an e-mail dated October 1, 2002, from F. Wentz to J. Johnson he states that "I'd like to still suggest we keep the staffing higher during Hybrid." Ex. ATC-893. The spreadsheet attached to the e-mail shows Flywheel n/storage as 262 employees for a reduction of 210 employees. Ex. ATC-893 at 3. The plan attached to the e-mail shows that facility/equipment maintenance personnel would be centralized out of Fairbanks and facilities (except for PS1) would not be manned with operations personnel. Permanent Living Quarters would remain at PS 4 and 5. *Id.* at 12. Security would be on site at manned and operating facilities. Oil spill response personnel would be stationed at PS 4 & 5 and live on site. *Id.* at 5-6. PS 1 would have metering, maintenance and OSCP response personnel stationed there, living at the producer facilities. *Id.* at 4.

Funding of SCADA 2002:

392. The record evidence indicates that the money to fund the Control System Strategic Framework (CSSF), that is the actual physical replacement of the SCADA system (not the control systems at the pump stations), is allocated in AFE-F370 on October 2, 2002. Ex. ATC-152. It seems that slightly more than two (2) years (August 2, 2000 to October 2, 2002) elapsed between the production of Kenonic Final Report on CSSF and the issuance of an AFE to ". . . fully fund the work required to replace the OCC Supervisory Control and Data Acquisition (SCADA) host system as well as consolidate and replace Data Historian (process historical archiver) systems" (*see* ATC-152: 5). This September 30, 2002, AFE states that this is a stand-alone project and estimates the cost at $8,400,000. Ex. ATC 152 at 6. It also states that the timing of the project provides the opportunity to reduce the costs of future initiatives such as pump station electrification since it eliminates the need to redesign the SCADA to be incorporated into the other

20140227-3052 FERC PDF (Unofficial) 02/27/2014

projects. *Id.* AFE-F370 is signed by D. Hisey for D. Wight (Title: President and CEO) on October 3, 2002, and requested approval from the Owners by November 1, 2002. The business case for replacing the SCADA Host/Historian is future cost reductions related to leveraging new automation and monitoring capabilities for efficient and proactive maintenance of the pipeline. The SCADA Host and Data Historian are core to delivering the goal of reducing O&M costs. Ex. *Id.* at 11.

393. As stated in AFE-F180, the proposed improvements of the SCADA system is based on the recommendation in the Control and Telecommunications Long Range Plan Conceptual Study issued in May of 1997 (Volume 1, Appendix A: Scope of Work-Descriptions). The C&T LRP is part of this record and clearly, as stated above, is the basis for the Kenonic Report (August 2, 2000) which was funded by AFE-F180 (Exhibit ATC-110) on April 20, 2000. ATC-102 as discussed previously is commonly referred to as "The Bailey Report" which is the "C&T LRP." As discussed earlier, the suggestions contained in the Bailey Report would save $20 million dollars per year. *See* Ex. ATC-102 at 69. Therefore, it is clear from the record evidence (the TAPS Carriers own exhibits) that the time which elapsed from the proposed suggestions in the Bailey Report (May 7, 1997) to this issuance of the funding mechanism for the updating of SCADA or AFE-F370 (October 2, 2002), is five (5) years, four (4) months and twenty-six (26) days. The "cost" to Owners for this time, as estimated in "The Bailey Report" valuation of $20,000,000 per year in lost savings opportunity, is $108,091,324.20. It is noted that the $20,000,000 per year included SCADA and control upgrades. That is, over $108 million dollars was lost by the extended period of decision making where no indication of importance or concern was shown with respect to "capturable savings." This is a conservative estimate since the savings as reported in Bailey is based upon upgrading SCADA and controls. While this number only identifies lost opportunity costs in terms of SCADA alone. This will be compared to the motivations that would later underpin the Owners desires for a speedy implementation of Strategic Reconfiguration with an aggressive schedule that had "zero float" with perfect construction execution and planned to meet an unrealistic construction/design schedule.

Email October 3, 2002

394. J. DeHaas wrote an e-mail to A. M. White on Strategic Reconfiguration dated October 3, 2002. Among other things DeHaas states that the only reason to immediately upgrade the control systems of the MLU's would be "if total remote operations is desired and is viable. Additionally he states: "I believe it is somewhat stretching the situation to assume that all these projects have to be done within the next few years, regardless, and use that as part of the premise and justification for installation of totally new equipment. A lot of this equipment can be maintained nearly indefinitely, with minor capital investments along the way." Ex. SOA-21 at 1.[266] He states that an aspect of justification

[266] DeHaas states that there are a few minor issues with the control systems (quality of on-skid wiring, and the Omni Guard temperature monitoring system) they are

20140227-3052 FERC PDF (Unofficial) 02/27/2014

based on capital investment that would have to be done due to life-cycle issues (relative to existing equipment) is a subjective matter. *Id.* Concerning the reconfiguration proposal DeHaas' opinion is that the costs estimates are low by a large amount. "Most of the estimates appear to be based on individual hardware package costs, as delivered. There doesn't seem to be nearly enough included for engineering, site construction and all the other activities that must take place. A thorough cost estimate has to be broken out and include engineering, labor, travel, lodging, training, commissioning, spares, safety, environmental, project management, overhead(s), engineering changes, etc." *Id.* at 2.

Email October 9-10, 2002

395. In an email dated October 9, 2002, J. Barrett (Conoco) summarizes a meeting that took place earlier that day. Ex. SOA-160 at 2. He states that it was agreed that the decision document and the LRP are both due on October 25, 2002. *Id.*at 2. "These documents will be prepared with Owner Planning Team involvement to make sure each company receives the appropriate information for their subsequent evaluation." *Id.* Additionally, he states that the decision document has to provide sufficient information to support a choice of direction for the path forward. "The Owners will evaluate the data and decide on an alternative." *Id.* He states that "as we see it, there are three choices: (1) move forward on pump station electrification and stop work on the Hybrid case, select the hybrid case and discontinue work on electrification, or continue working on both." He goes on to state that to make the decision, the Owners would like to see a 10-year LRP spending profile for both the Hybrid and Electrification cases, including a discussion of sensitivities and risks associated with each alternative. *Id.*

396. On October 10, 2002, K. Brown responds to J. Barret. Brown states that BP is not interested in continuing to work the hybrid case nor will we support it as a way forward. He further states he is concerned that "we weaken our resources working an option that would not have sufficient owner support to proceed." *Id.* 1-2.

397. P. Flood (Conoco) responds to K. Brown the same day and states that he appreciates Brown's perspective and "ask your patience as ConocoPhillips finds its own answers." *Id.* at 1.

Proposed 2003 Operating Plan and Long Range Plan

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obsolete, but we have been getting by. They could be replaced relatively cheaply, if done within operations engineering. The only reason to immediately upgrade the control systems would be if total remote operations is desired and is viable. *Id.* He adds that the primary justification for installing new equipment should come from reductions in manpower, fuel costs, and perhaps maintenance costs. "The latter con go either way – i.e. be a plus or a minus." *Id.* at 1.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

398. Ex. ATC-153 is Alyeska's "Proposed 2003 Operating Plan and Long Range Plan" dated October 25, 2002. This is the first substantive LRP prepared in several years and it was done in conjunction with the TAPS Owners Planning Team. *Id.* at 4. According to this document it represents a major change in Alyeska's approach to strategic planning. The plan is based on a set of planning assumptions developed by Alyeska and the TAPS Owners. The executive summary also mentions that it is based on the Electrification Reinvestment Strategy. Ex. ATC-153 at 4. This strategy will result in significant cost and staff reductions, from 2002, expense will decline by $124M/yr by the end of the planning period using 2002 as base ($8M costs reductions from 2002 realignment are included in this figure). *Id.* at 4 and 11. By 2007, when the electrification reinvestment is completed, the annual cost reduction from the 2002 Plan will be $108.5M/year. Planned staff reductions total 226 employees and 164 baseline contractors a total reduction of 367 employees and 254 baseline contractors from the pre 2002 Realignment levels.[267] The projected reductions will be realized as a result of a greatly reduced pump station asset base, which will require less overall direct and indirect support personnel. *Id.* at 4.

399. The 2003 Long Range Plan treats the Electrification Reinvestment Strategy as the base case strategy. Consequently, the new pipeline asset strategy is leveraged upon pump station electrification, enhanced controls systems, and regional maintenance and OSCP centers. *Id.* at 10. Additionally, the costs associated with powering PS1 is absorbed by the Owners who pay in kind by natural gas which is then converted to power. The savings in natural gas to the owners is unknown to Alyeska, but should be considered by the Owners as a reduction in the cost of the Reinvestment case. The plan further assumed that starting in 2006 the cost of PS1 electricity purchased by Alyeska is approximately $10M annually. *Id.* at 11.

400. In the plan "switching costs" contain estimates of severance costs associated with the Reinvestment case as well as costs associated with inventory write-offs, demolition, training, and the repositioning of oil spill contingency equipment. The costs elements need additional study (except the severance cost estimates). *Id.*

401. This document mentions that the Long Range Asset Plan was developed by the Joint Alyeska/Owner Strategic Planning Team and that Plan is also known as the Electrification Strategy or Strategic Reconfiguration. *Id.* at 35. The planning assumptions of the Plan are built around pump station electrification and minimum footprint strategy. *Id.* at 42. The plan's inflation assumption is said to be zero to allow the Owners to use their own assumptions. *Id.* at 43. Additionally, the 2003 throughput is

[267] Employee reductions of 150 from the February 2002 base and 150 in baseline contractors (99 baseline contractor reductions are attributed to the 2002 Realignment). *Id.* at 59 and 63. The cost target reduction from staffing and contractor reductions was $7.5M in 2002, increasing to $26M and $28M in future years. *Id.* at 63.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

estimated to be 1.083 MMBD for the entire planning period, throughput is forecast to increase approximately 348 MMB or 0.95 MMBD over the 2002 LRP. *Id.* Note that the chart attached to this Plan shows throughput declining every year and starting approximately in 2004 going below 1.1MMB. *Id.* at 44.

402. The 2003 Operating & LRP Assumptions state that significant personnel reductions are not expected for 2003. We expect Alyeska staffing will be reduced to approximately 710 employees and 585 baseline contractors once the pipeline asset strategy is implemented with additional reductions during the remainder of the planning horizon." *Id*. at 45. The 2003 Operating Plan has a chart showing personnel levels for 2003-2012. In 2003 the total is 1,635 employees, in 2004 the total is 1,567, in 2005 the total is 1,530, in 2006 the total is 1,295 in 2007 the total is 1,273, in 2008 the total is 1,268, in 2009 the total is 1,259. Starting with 2010 it levels off to a total 1,245 employees and continues as such for 2011 and 2012. *Id.* at 16.

403. An explanation of Strategic Reconfiguration is described in the LRP. First it mentions that the pump stations will be automated to allow unattended operation, remote monitoring and control. PS 2, 6, 8 and 10 will be "rampdown." This shows a previous authorization AFE S016. *Id.* at 104. The Remote Gate Valve Control System will be upgraded. Again this shows previous authorization (F411). *Id.* The SCADA Host will be replaced. This has been authorized (F370). *Id.*at 105. The Ramp-Down Station Relief System is to be modified. This has an authorization (S015). Next, pump station electrification is described. The document states that "unmanned stations are the industry standard for remote locations, with electric drivers where power is available. The Avons are in need of control system replacement due to age and obsolescence. APSC has studied replacing the existing Avon gas generators with electric drivers. Replacing the Avon gas generators with smaller electric drivers would provide for a safer/simpler and more economical ongoing operation." *Id.* at 106. PS 3 generates its own power by 3 operating 400kW Garretts and two spare 800kW Solars. Replacement of the small generators with large/new turbines will provide a more reliable source of power at an unmanned station. *Id.* at 107. The same thing is stated for PS 4, except that it generates its own power by 2 operating 400 kW Garretts, with a spare one and one spare 800kW Solar.[268] PS 9 had power "approx. 500kW" supplied by GVEA, the document states that the power company had presented a paper to upgrade the tie-line to provide sufficient power for the station and electric driver needs. Alternatively, Alyeska could supply large

[268] The LRP lists the following AFE numbers for these: (S022) for PS 3 with a budget request of $14M capital, (S021) for PS 4 with a budget request of $10M capital, (S012) for PS09 with a budget request of $10M capital and (S009) for PS01 with a budget request of $8M capital. There is no clear explanation in this record as to what happened to some of the AFEs listed here. Compare the "decoder" Ex. AT-493 (no mention of these AFEs) with Ex. SOA-389 at 4 which lists S021 but not the others. *See also* Ex. SOA-131.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

power-generation on site. PS 9 had one spare 400kW Garrett, and one spare 800 kW Solar. "Since PS9 is on the utility grid, the power generation scheme is not as expensive to operate and maintain as more remote stations. However, upgrading the tie-line, new MCCs, and a new load shed scheme provides for more reliable power and pumping at an unmanned station." *Id.* at 107.

404. The LRP states that PS 1 generates its own power by four 400kW Garretts with one spare, and two spare 800kW Solars. "The proposal is to place the station onto the North Slope Power grid and install new electric drivers for the mainline pumps, booster pumps, and fuel gas compressors (if required). "Replacing the Avon gas generators with 3 each approx. 5000 hp electric drivers…" The plan was to eliminate the Garretts for primary generation and tie-in to the grid. *Id.* at 108.

405. Hybrid is described in the LRP. It states it utilizes existing equipment at the pump stations with upgrades in controls and instrumentation to allow the facilities to operate "without operational manning." If this option were pursued the expenses "would decline to $426M in 2012 from $516M in 2003. *Id.* at 114. Maintenance personnel would be centralized out of Fairbanks, facilities would be de-manned (no operations personnel) except for PS1, PLQs would remain at PS4 and PS5. *Id.*at 122. Security would be retained on site at manned and operating facilities. *Id.* Hybrid would reduce staff by 94 employees and 71 contractors over the planning period. *Id.* at 124.

Electrification vs. Hybrid Document

406. Exhibit ATC-154 is titled Electrification vs. Hybrid Decision Document and was issued on October 28, 2002.[269] This document identifies two possible pathways for reinvesting in TAPS to, "provide for highly efficient and reliable crude transportation for the next thirty years." Ex. ATC-154 at 6. The recommendation is reinvestment in TAPS through the replacement of existing pump stations with new electric driven pumps. Removal of PS12 in 2003 and, continuing operations at PS7 with its installed equipment and finalizing the decision to electrify, upgrade or remove PS7 by the end of the first quarter of 2004 are also recommended. *Id.* The document requests that electrification (reinvestment) be approved and Hybrid not be considered any longer. *Id.* at 8.

407. This document is principally an economic evaluation of alternatives for reinvestment in the TAPS system with no consideration or discussion of possible pitfalls and/or problems that are normally encountered in large construction projects. Projections in this report, including expected pipeline throughput (*Id.* at 37), Alaska Fire Marshal acceptance of un-approved plans for remediation of long standing Alaska Fire Code

[269] Exhibit SOA-161 is also titled "Electrification vs. Hybrid Decision Analysis and Summary an appears to be a summary of the final document which is ATC-154. Ex. SOA-161 appears to be slides for a presentation. It is dated by Ex. J-2 as October 22, 2002.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

violations, availability of commercial power (for energy and capacity) at PS1, PS9 and PS12 (*Id.* at 25) and the electrification project schedule (*Id.* at 48) are, at best, overly optimistic. No consideration, discussion or planning was done (at least up to this point in time) to even remotely acknowledge the possibility of failing to meet such ambitious goals or the deleterious effects of not achieving the goals as put forth in this report. *Id.* at 7.

408. The aspects of electrification discussed are that it removes most of the existing infrastructure, (*Id.* at 30) involves installing new equipment designed for that purpose by the manufacturer. This provides the ability to use competitive bidding for equipment, the new equipment is tested off-line before installing, the vast amount of new construction work is done off-site at the manufacturer where conditions are controlled, liquid turbine fuel is virtually eliminated with electrification. *Id.* at 7. If any of these assumptions are incorrect (as eventually happened), the economics of this document are invalid.

409. For instance, the document assumes 5200 drawings would be eliminated with the electrification option (the revision effort on these drawings is approximately $500 thousand per year). If all the buildings were ultimately not eliminated, this assumption is not valid. Additionally, the document states, "major mechanical equipment is operating extremely well. Reliability is very high and unplanned shutdowns are rare. It is working so well that maintenance personnel are not retaining their skills in such tasks as changing mainline pump seals, etc. *Id.* at 31. However, the facilities that house the pumps . . . are very expensive to operate and maintain. Many of the utilities such as the fire system, fuel system, electrical distribution system, and the waste system have regulatory issues that exacerbate the issue. Reuse of the current mainline pumps was examined in the confirmation study. The installation of a single 18000HP motor and variable frequency drive (VFD) was not recommended. The cost of a pump (~$200,000) is a very small percentage of the overall capital cost of an electrified pump station (~$25-30 million) and should not drive the decision." *Id.* at 32.

410. It continues along the following lines: "[t]he most significant difference between the Hybrid and Electrification scenarios is the continuing O&M cost. In both cases, the control systems will be replaced and the equipment automated. However, in the Hybrid case, the remaining facilities are still 25+ years old and operating costs continue at near current levels. In the Electrified case, the equipment is all new, the amount of facilities and equipment is reduced significantly, and the resulting O&M costs are reduced." *Id.* If any of the assumption that electrification would remove all the buildings was not valid, the conclusions of the study are not valid.

411. In considering financial risk from construction no allowance was made for any major delays or problems. Ex. ATC154 at 33. Such an assumption is suspect. The likelihood of scope creep was assumed to be higher for hybrid. *Id.* Again if this assumption was not valid, the conclusions of the study are suspect. Another assumption is that the pump stations will no longer have operators on site and maintenance personnel may be present but not required and would be dispatched from Fairbanks or regional

20140227-3052 FERC PDF (Unofficial) 02/27/2014

centers at PS1, 4 and 5, Glenallen or Valdez, security personnel would be reduce also. *Id.*at 35.

412. Power from the grid or regional maintenance have not been negotiated and the document recommends expedited action due to the Fire Marshal's deadline of 2005 for fire systems work. *Id.* Note that this document modifies assumptions in the LRP and indicates use of the LRP costs. *Id.*at 17. It states that they removed the fuel costs for PS1 assuming the gas would be provided as in-kind by the owners as provided at the time of the document. *Id.* If this change had not been made Reinvestment would show $10M per year and Hybrid $0. The LRP costs were further modified to reflect removal of PS12 and deferral of PS7 electrification. *Id.* No spare pumps were provided for either option. *Id.*at 29. This is contrary to record evidence that there were plenty of spares for the legacy equipment.

413. This report culls data and analysis from previous studies and reports as foundational underpinnings for the analysis presented in Exhibit ATC-154 while never explicitly identifying, or providing, the source material used to support the economic analysis presented. For one specific example, in Section 3, Financial, figure 3-1 (titled, Hybrid Case- Financial Forecast by Cost Category) is a table identifying inputs used for a Net Present Value calculation. This table alleges to represent a financial forecast of costs but certain entries in this table raise significant questions as to the veracity of such projections. *Id.* at 18. Many entries in the outlying years represent little to no change in projected costs: for one such example see the row labeled Materials & Supplies (ATC-154:18). This row shows no growth in costs for Materials & Supplies. While this fact alone normally would cause little concern, it is the cumulative abnormalities seen throughout this document, and addressed more fully below, that raise many questions and cast serious doubt with respect to the recommendations contained therein. Concerns with the Materials & Supplies line item include: why, and on what basis, over a ten year period do Material & Supplies decrease from $16,580,000 in 2003 to $16,111,000 in 2012 (representing $469,000 decrease in ten years), what inflationary pressures on costs are assumed by each individual Carriers economic analyses in outlying years[270], how and on what basis were these numbers generated. These types of questions are usually answered in underlying work papers and supporting materials. No such documentation exists for Exhibit ATC-154 and the utter lack of supporting materials is a noted

[270] As explained in ATC-153 at page 43, "the Long Range Plan inflation assumption is assumed to be zero." This is relevant to the discussion here, with respect to ATC-154, because the economic analysis presented in ATC-154 is based upon two alternate Long Range Plans (*see* ATC-154 at 17). ATC-153 states that inflationary pressures are assumed to be zero to allow for each individual carrier to apply their own assumptions and execute their own respective economic analyses. This fact further complicates a complete understanding of the basic inputs of ANY economic analysis represented in ATC-154.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

phenomenon in many of the submitted documentation in this case. Without further explanation and support for the data used in calculating the Net Present Values presented in Exhibit ATC-154, little weight can be afforded to the conclusion contained therein.

414. Problems not dissimilar to the above described concerns are replete throughout Exhibit ATC-154. An exhaustive analysis of ATC-154 is possible, but such an endeavor is not necessary here because so many problematic statements exist in Exhibit ATC-154; this section will deal with the most egregious failings of this Exhibit. The first and most pervasive deficiency of the analysis presented in ATC-154 is the fact that the proposed TAPS system reinvestment strategies are inconsistent and do not align with prior studies. Up to and until the production of Exhibit ATC-154 the concept of a "Hybrid" Option for Reinvestment existed vaguely across multiple studies, disjointed and not uniform in concept, engineering, scope or planning.[271]

415. The term "Hybrid" is not a defined term until the appearance of Exhibit ATC-154. The term "Hybrid" has been used in Strategic Reconfiguration (SR) to represent at least four proposed upgrades for the TAPS pipeline. Various studies have been identified as contributing to the ultimate definition of a "Hybrid" scheme: The Bailey Report (ATC-102), a 1999 review of the Bailey Report (ATC-105), various Kennonic Studies (*i.e.*, ATC-751, 752), and others[272]. Ultimately, one can only understand what is meant by the term "Hybrid" with the definition provided for in Exhibit ATC-154. As such no one study, up and until October 28, 2002, ever considered the exact Hybrid scheme(s) as presented in Exhibit ATC-154 at 36. The Hybrid scheme as proposed in ATC-154 is an amalgamation of pieces and parts of other studies blended together to form what is described in ATC-154 as the "Hybrid Option."

416. Ex. ATC-154 defines the Hybrid alternative as reducing ". . . the number of mainline units to those required to meet the throughput requirements. The existing Avon driven mainline pumps would be retained in service, however, their controls and monitoring would be upgraded to allow for unattended operation. The bulk of the existing station facilities would be retained as they are required to support the operation of the mainline units. Controls and monitoring for the existing station facilities would be installed or upgraded to allow for unmanned operation."[273] Instrumentation would be

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[271] The first mention of hybrid in the Carriers documents are on a table in Ex. ATC-141 which are supporting documents for a telephone conference on February 5, 2002. Ex. ATC-141 at 13. It is also described in the 2003 LRP (dated October 2002). Ex. ATC-153 at 114.

[272] Some of these studies are not in this record, such as a 1994 Telecommunications Study upon which The Bailey Report was based.

[273] Ex. ATC-154:12. This meant operated and monitored remotely and unattended. *Id.* at 13. The mainline pump utilities (lube oil skids, anti-icing, cooling

20140227-3052 FERC PDF (Unofficial) 02/27/2014

installed to allow monitoring and control of the necessary station utility systems. *Id.* at 15. The necessary major maintenance to existing equipment would be provided, all facilities needed to operate would be automated to operate without on-site personnel, and the SCADA and telecommunications systems would be replaced. *Id.* at 36.

417. A total of eleven options[274] to implement SR were evaluated. Four options[275] which retain the legacy MLUs would reduce the number of mainline units and retain the original Avon/Cooper MLUs. Options 2, 3, 4 and 5 would upgrade, and add to, the monitoring abilities and controls functions that would allow the legacy Avon/Cooper MLUs to be operated fully unattended. Thus, at this time (up and until October 28, 2002) at least four different implementations and schemes could reasonably be described as "Hybrid," yet conceptual engineering studies alleging to study "Hybrid" (*i.e.*, ATC-751 and ATC-752) contemplate automation and control upgrades for all existing MLUs[276]. This is not the only instance of confusion where the term "Hybrid" morphs substantially from one scheme to another. Of the eleven options the hybrid favorite is option 5. Ex. ATC 154 at 38. This option entailed 2 MLUs at PS1 and PS 9 with 1 MLU at PS 3 and 4 (bypass PS7 and 12 w/DRA and connect PS1 to grid and electrify booster pumps) – minimum spares, and 1.12MMBD capacity.[277] *Id.* at 36. Note that previous studies had rejected this option. *See* ATC-105.

418. Placing aside for the moment the fact that the Hybrid Option, as studied and described in ATC-154, has never been subjected to a stand-alone, rigorous engineering analysis, the Hybrid Option suffers from other significant flaws, such as the lack of supporting work papers. As mentioned above, supporting information for the assumptions and projections contained in ATC-154 are not provided. This fact alone detracts from the judicial weight and evidentiary value of this document, and a closer examination of the data contained in this exhibit only goes to reinforce this perception.

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systems, and sumps) would be upgraded to allow for remote monitoring and unattended operation. *Id.*

[274] Ex. ATC-154 at 36.

[275] Options 2, 3, 4, and 5, in Ex. ATC-154 at 36.

[276] *See* Ex. ATC-751 at 7-9: at PS1, 3, 4, 9 and 12, all three (3) MLUs at each pump station are being studied for control upgrades, and PS 7 two (2) MLUs are being studied for control upgrades.

[277] The document states that Electrification and Hybrid had some common attributes: operationally unmanned facilities (except for PS1); maintenance response centralized in Fairbanks; response personnel located at PS1/Prudhoe Bay, PS4, PS5, Fairbanks, Glennallen and Valdez; minimal sparing of on-line equipment; throughput capacity exceeds that required by production forecasts and ramped down facilities would be removed to the foundations. Ex. ATC-154 at 9. Pomeroy testified that the PLQ at PS 3 could be eliminated under both Hybrid and Electrification. Tr. 7926:5-7.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

419. Some examples that illustrate the negative implications of not providing supporting documentation are easily demonstrable when one examines certain aspects of the analysis preformed in Exhibit ATC-154. As one example, let us examine a statement in Exhibit ATC-154 at 32. In Section 4.1.7 (titled, Maintenance and Operability Issues) where it is stated that, "[o]ther than the potential startup issues noted above, operation and maintenance in the Hybrid case will be similar to present experience." This statement is not credible. The Hybrid Option includes reducing the number of mainline units (as discussed above), personnel reductions, the addition of a new SCADA system, the addition of new monitoring equipment, and new control points[278] to achieve full automation of the legacy Avon/Cooper MLUs. These new monitoring and control points[279] and the reduction of the number of operating MLUs present a scenario where Alyeska will be responsible for maintaining fewer MLUs, have fewer employees in remote locations, and will have additional operational information[280] to perform predictive and preventive maintenance. Thus, a reasonable question is raised with respect to operation and maintenance in the Hybrid case as compared to operations prior to SR and post SR.

420. It is not explained nor is there any documentation in this record on how the new control systems[281] functions and requirements for Operation and Maintenance would, or could be, similar to operating TAPS utilizing upgraded legacy MLUs. Logic dictates that new Operation and Maintenance procedures are necessary when installing new equipment. The Hybrid scheme as proposed in Exhibit ATC-154 reduces the number of legacy MLUs in operation and adds control equipment to achieve full remote operations for the legacy MLUs. These are not insignificant changes in the TAPS System and it behooves a sentient being to accept the verisimilitude of such a statement without some form of objective verification demonstrating at least a tenuous connection between such a bald statement and reality. When no supporting documentation is offered (and no explanation given) for the statement like, "operation and maintenance in the Hybrid case will be similar to present experience," little judicial weight can be afforded to this document.

421. While the above outlined deficiencies are reason enough to cast aside the recommendations in Exhibit ATC-154 it is by no means its only deficiency. Circling back to the notion that the Hybrid Option is an amalgamation cobbled together from prior studies, one can quickly become concerned with the underlying source data used to estimate the costs of rehabilitating and automating the legacy MLUs. Witness Howitt

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[278] New control elements will be installed on both on the legacy MLUs and ancillary equipment in the pump stations.

[279] Associated with the installation of a new SCADA and Host Control Systems

[280] *i.e.*, new and improved MLU monitoring with new sensor equipment.

[281] For example: SCADA, remote Host Controller, new human-machine interfaces, Remote Gate Valve additions/replacements, etc.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

under cross examination confirmed that the genesis of Hybrid was other studies. Howitt stated, ". . .It had all this work done for literally ten years -- no, not quite, eight years, on the whole control systems upgrade, hybrid configuration, and it had progressed through the Kenonic work" (Tr. 4590:12-16). Howitt at the time ATC-154 was produced was Senior Executive Advisor to Alyeska's COO and CEO with respect to the SR program and served as the liaison between the Alyeska Operations organization and the SR Project Management Team. Ex. ATC-19 at 3. His knowledge and statements with respect to the Hybrid option confirms the patchwork design of the option which has become to be known as the Hybrid Option.

422. Alyeska, through Witness Howitt, seems to claim in the above statement at Trial that a Hybrid configuration was studied for eight years. It is unknown as to exactly what Witness Howitt was referring to in his cross examination since, as discussed above, a Hybrid scheme was not fully defined until the production of ATC-154 in October 2002. Howitt's claim that some form of a Hybrid configuration was studied for eight years can be somewhat substantiated in the record evidence, but a closer examination of the studies to which Howitt refers to raises more question than can be answered within the confines of this record.

423. As discussed prior, an examination of conceptual engineering studies performed for a Hybrid scheme between 1994 and 2002 (and discussed prior) do not contain cost breakdowns or any substantive cost information. As conceptual engineering documents, these prior studies (on which ATC-154 is based) are known to have significant wide cost estimates varying on the order of +30% to +100%. Prior studies[282] include work at PS7 and PS12 and include work on *all* legacy MLUs at the pump stations, with little consideration of removing *any* legacy MLUs (and those associated costs of removal) from Alyeska's system. Prior studies, specifically the Bailey Report[283] and the 1999 Review of the Bailey Report[284] both examine and reject electrification of certain pump stations.[285] The Bailey Report explicitly examined full automation of TAPS and rejected the concept in favor of a less automated scheme that required operators to be present at the pump stations during the day and turned operations over to the OCC at night.

424. There is no convincing and/or well supported explanation in this record as to why prior studies and recommendations were discarded in favor of a "clean slate" approach

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[282] For example, Exhibits ATC-751 and 752.

[283] Exhibit ATC-102.

[284] Exhibit ATC-105.

[285] The only pump stations considered for installation of electric pumping motors are those pump stations where commercial power from 3rd party suppliers were present, specifically PS1 and PS9.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

which contemplated wholesale reconfiguration of the TAPS pumping systems. The only explanations given for the preference of new electrified MLUs over rehabilitation and upgrading existing MLUs are contained in Exhibit ATC-154 and all the explanations are given in terms of economics. The economics generated in ATC-154 are suspect; one example is discussed above. While the economic supporting details are missing from ATC-154, so too are details in engineering. The document recommends proceeding to preliminary engineering for Electrification. Ex. ATC-154 at 8.

425. Specifically, assumptions[286] utilized in Ex. ATC-154, with respect to the availability of electric capacity and energy at PS1, PS9 and PS12, are troublesome. To assume that both electric capacity and electric energy are available at remote pump stations without entering into discussions with third party suppliers to know how much electric service is available borders on negligence. When the Carriers plan on electrifying its MLUs and do not preform the basic tasks of asking third party providers about the availability or cost[287] of electric service in that area, serious doubts as to the thoroughness and purpose of ATC-154 are raised. At a minimum, one would expect to see supporting record evidence to assure that electric service from third parties will be available and the assumed economics (in Exhibit ATC-154) were reasonable. This Tribunal would expect to see evidence such as, a request for electric service, a request for electric interconnection to a third party electric system, a power flow study to know the level of reliable service that can be provided, estimated interconnection costs from the supplying utility, or other documents to show that the economics parameters that are assumed at least carry the weight of being probable if not possible. A pie in the sky assumption that certain pumping stations would be placed on power grids[288] and then to use that assumption in a comparative economic analysis defies all logic and is an anathema to good business practices.

426. Similar engineering concerns arise when one considers the proposed project schedule for field construction. Project timing is discussed in Section 7 of Exhibit ATC-154 (*see* page 48). The table on page 48 is a black and white reproduction of a table that indicates that PS1, 3, and 4 will have "Construction/Procurement" activities taking place between mid 2004 through at least the first quarter of 2005. This raises significant concerns with the construction length and timing since little (if any) major construction can occur over the winter months in Alaska. This chart seems to indicate that a major

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[286] For example see the assumption stated at ATC-154 at 25, "PS01, PS09, and PS 12 were assumed to be placed on power grids. The costs are based on 1.1 mmbpd throughput capacity." Mmbpd is an acronym meaning million barrel (of oil) per day.

[287] From ATC-153 at 42, "Electricity Costs: Electricity that is acquired from third party generators that will supply PS 1 (2006) and PS 9 starting in 2005 is assumed to cost $.05/kwh. PS 12 power is assumed to cost $.15/kwh starting in 2004."

[288] *See* ATC-154 at 9 and 25-26.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

portion of Construction and Procurement will occur in the winter period which is not creditable.

427. Additionally a comparison and contrast with other projects in a conceptual engineering phase raises concerns as to the feasibility of completing such a large project in the amount of time allocated in ATC-154 for the SR project. The Bailey Report[289] at page 52 shows a table (Figure 3.9, Summary Tasks Program Schedule) which indicates the work outlined in the Bailey Report would take a total time of just shy of four (4) years to complete the goal of upgrading the SCADA and telecommunication systems on TAPS. According to the Bailey Report in Figure 3.9, the average construction time at individual pump stations was to last for about 1 year.[290] The estimated construction time at each pump station to implement SR Electrification Option is represented as taking less than one year.[291] The SR project is bigger, more complex and far more costly than what was considered in the Bailey Report, yet the construction estimates time line is shorter by at least 3 months. Nowhere in this Record has Alyeska, its contractors, or parent companies ever satisfactorily explained on what basis could SR be constructed in far less time than a smaller, less complex project like that project described in the Bailey Report. Additionally, the work to upgrade the SCADA and Telecommunications equipment described in the Bailey Report is subsumed within the SR project with many more major projects included in SR than what is considered in the Bailey Report. How the SR project with its additional complexities, work and significant modernization efforts could take less time than the work described in the Bailey Report detracts from the overall weight that can be afforded to Exhibit ATC-154.

428. Aggressive construction schedules, unverified assumptions, and unsupported conclusions are not singular in nature, but permeate Exhibit ATC-154. Another example demonstrating the use of over simplified and unverified assumptions is Alyeska's assumption of the action of the State of Alaska Fire Marshal. Alyeska assumed that the State Fire Marshal would not require certain investments to fire safety systems agreed to prior to 2002 to ameliorate defects and deficiencies found on TAPS in prior years. Alyeska assumed that de-manning pump stations in general and specific buildings and structures in particular would allow for Alyeska to eliminate fire and safety protection systems within TAPS.[292] Alyeska was wrong in its assumptions with respect to the

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[289] Exhibit ATC-102.

[290] The one year construction time is an eyeball average estimation of the construction duration at individual pump stations. *See* Exhibit ATC-102 at page 52, Figure 3.9, specifically ID numbers 11, 51, 92, 100, 108, 116 and 124.

[291] Ex. ATC-154 at 48 (Project Schedule – Electrified Option; the graphics for the Project Schedule indicate on average 3 quarters of a year or 9 months.)

[292] Ex. ATC-154 at 8 ("The Electrification vs Hybrid decision needs to be made by December 2002 to maintain a schedule that avoids making unnecessary investments in

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Alaska State Fire Code.[293] One would expect that such a major assumption with implications in the economic analysis would be verified, researched or confirmed with the State Fire Marshal prior to including a substantial savings in an economic analysis decision package. Moreover, once this assumption was proved wrong, the economic analysis had to be re-worked since this assumption was invalid. There is no evidence in this record that this analysis was ever amended.

429. In addition, to all the internal inconsistencies in this document it will not be given significant weight in terms of proving the prudency of the undertaking since this document was done at the conceptual engineering stage. This record is devoid of any evidence that this document was ever updated once preliminary engineering was completed. However, the document does have some probative value since it shows what the owners knew before they undertook the project. Finally, the document will not be given significant weight since the electrification alternative considered was tying PS1 and PS9 to the grid. *Id.* at 25. This is not what was ultimately built. As a matter of fact, what is being built in PS 1 is an unknown in this record. So the probative value of the numbers is zero. Note that the document does not attribute significant staff changes to the Oil Spill Contingency Plan.[294] Ex. ATC-154.

Emails November 2002

430. In an e-mail on November 20, 2002, J. Riordan states "Alyeska has landed on the investment cost, project costs, and savings for the Electrification and Hybrid cases and J. Barrett has asked that I send this to each of you for reference." Ex. ATC-157. Attached are electrification and hybrid economics charts. *Id.* at 2 and 3. The inference from this document is that at the time the Electrification vs. Hybrid document was done the "economics" were still being worked on." This is supported by an email from P. Flood dated November 1, 2002, where he states that "the Hybrid Case projects list in the LRP book seems to be way off this list (*see* reconciliation in Hybrid worksheet) and the Decision Document Appendix B totals for the Hybrid Case are not correct (there was an apparent spreadsheet error for the values shown (they don't add up). Frankly, I'm

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the existing systems. An example, is the fire systems work: the design must begin in 2003 to maintain the State Fire Marshal's completion deadline of 2005. Delaying the Electrification decision requires that design work proceed on equipment that ultimately may not be used.").

[293] Ex. ATC-233 at 9 ("The SR Design criteria where only 20% of the walls removed and the building goes cold would not require a fire protection system. Such a design does not meet State building code requirements.").

[294] The document discusses the potential air quality issues of the GE LM2XXX at PS 9 which would exceed the threshold for sulfur dioxide. Ex. AT-154 at 51.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

concerned there wasn't sufficient time for QC and a review is in order-suggestions?" Ex. ATC-155.

"*Alyeska 2003 Budget Situation*"

431. As of November 21, 2002, the BP Mid Stream Alaska group was completing due diligence on Alyeska's 2003 budget proposal. Ex. SOA-184. One of the priorities listed in this document (Alyeska 2003 Budget Situation) is to "Drive the electrification project to an early sanction." *Id.* at 2. It also states that "the biggest lever we have to advance projected 2004 savings into 2003 is the early approval of the pump station electrification project." *Id.* at 1.

Stream of emails on Decision - BP wants electrification

432. On November 25, 2002, J. Barrett by email, provided additional analysis and summary documentation for the Electrification vs. Hybrid decision. He provides a brief executive summary of the results. Essentially, he states that the economics are positive for both Hybrid and Electrification but the NPV for electrification far exceeds Hybrid. Ex. SOA-182 at 4. Barrett points out, that electrification requires more up-front capital, but has more cost savings and higher confidence level. *Hybrid* requires less investment and saves more money in the first three years but the probability for success is lower and the savings are less. In addition, electrification provides environmental advantages which are not available with hybrid. He states that Alyeska is recommending electrification as the most effective alternative. According to Barrett, electrification provides a flexible, expedient, and cost-effective way for Alyeska to meet future production flow-rates, whether higher or lower than current forecasts. He points out that the decisions are mutually exclusive. *Id.*

433. A. Bolea responds: "How about a bold act of leadership on our part! I need nothing else to decide that BP wants to go ahead with developing the electrification. …Time is not on our side it just cost us money." *Id.* at 3. Meg Yaege responds, on November 27, 2002, that they are not prepared to make a decision until "at least the end of next week, and probably not until we get the final package from Alyeska with the full economics." She says she has seen new information … and the decision is more significant than it appears. "Once we move down this path, our next decision will be go or no go, so we'd better be absolutely sure we are going to want to "go" with electrification. We'll move this along as fast as we possibly can." *Id.*at 2. A. Bolea responds that "we need to get into real action and set targets and milestones for John and Alyeska. I don't want Alyeska to spend any more money evaluating the hybrid option – we are just burning time and money." *Id.* at 2. M. Tudor from Exxon opines that "John and the team needs to improve the clarity of what they are providing such that we can make these more informed earlier decisions." *Id.* at 1.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

434. Another e-mail dated November 25, 2002, from J. Barrett attaches additional analysis and summary documentation for the Electrification v. Hybrid" decision.[295] Ex. ATC-158. Without security or indirect staff the personnel reductions due to electrification would be 130. *Id.* at 7. Note that this includes PS 7 and 12. Electrification would cost $234 million and Hybrid $169 million. The avoided project savings for Hybrid according to this document is $70 million, electrification $152 million. PS 1 and PS 9 are assumed to be connected to the power grid. *Id.* at 8. Again as noted before, this exhibit does not have supporting documentation for the numbers.

Status Report

435. In a December 10-11, 2002, status report it is noted that there was work on two of thirteen alternatives. The cost estimates for both are "order of magnitude" just adequate to compare alternatives. It also states that the cost estimates and schedule do not include contingencies. Ex. SOA-197. This exhibit also indicates that they are still studying the power options (generate or purchase power and the terms and conditions). *Id.* at 2. Page 5 of this document indicates that the recommendation was to "stay on schedule for 3Q of 2005 (to fully realize savings)." It also points out that the current schedule is tight and delays can result in future cost escalation or lost savings. *Id.* at 5. Another recommendation was to commit to complete the Front-End-Loading process. The document points out that "up-front planning is the most important part of the project." In addition, it recommends using "peer reviews," and "plan the work; do it right the first time." *Id.* at 6.

436. The exhibit also states that the agencies have been briefed "beginning to engage." *Id.* at 7. Dealing with the cost estimates the document points out that the estimates are "order of magnitude," contingencies were not included. It points out that project management and Alyeska costs were not included and that the costs are adequate for comparing alternatives, but not for project funding. *Id.* at 9. Concerning the schedule the document points out that it is aggressive with very little flexibility. The current view indicates zero float for three years. The schedule will require timely decisions and flawless execution. In addition, it points out that the schedule will be optimized over the next few months. *Id.* at 9.

Cost Comparison December 2002

437. A cost comparison summary of electrification vs. Hybrid dated December 11, 2002 (TAPS Owner Presentation) shows the costs for Hybrid as $171 million: $6 million for construction costs, $67 million for control systems, $86 million for major

[295] The recommendation for electrification is justified as the best economic case, maximizing long-term sustainable cost savings, renews equipment/minimizes maintenance; highest probability of success; superior environmental solution, more flexibility to accommodate future flow forecasts. *Id.*at 5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

maintenance and $13 million for switching costs. For electrification the total costs are $234 million: $120 for construction, $38 million for control systems, $32 million for maintenance and $44 million for switching costs. A note on this document states that the schedule restates the data provided in the December 11-12, 2003, presentation to the TAPS Owners. Ex. SOA-162 "Summary." According to the note this are small corrections but no changes were made to the underlying assumptions. This note calls into question the veracity of this document since changes are being made to numbers in a presentation after the fact. Moreover, the year cited for the presentation is a year after the presentation took place (2003 instead of 2002). Hopefully, this was just a typo. It adds additional costs that could have been added to Hybrid that would have increased the net present value to electrification. It is concluded that this document will be given no weight since it is inferred that this document was made for litigation purposes.

Owners Meeting December 11-12, 2002

438. In a December 11-12, 2002, Owners meeting SR was discussed. On electrification Al "recommended that it be pursued through a "gate" process." Meg stated that PTAI cannot support dropping the "hybrid" case internally until it obtains more specific information from APSC. "The Owners agreed however that, the PTAI request notwithstanding, APSC is not to incur costs related to working the hybrid case any longer." Ex. SOA-185 at 4. As to staffing levels, "Lee identified a goal of 87 APSC headcount based on implementation of electrification, noting that there will be an interim level of staffing of 117 in 2003." *Id.* at 6. Staffing levels goals for 2003 will be 900. *Id.* at 9. J. Barrett noted that conceptual engineering is complete, having compared the two alternatives – electrification and the hybrid case. *Id.* Meg questioned how they could rely on the JTG and GE comparisons without further engineering. Ex. SOA-185 at 9. John responded that the analysis relies upon probabilities, which are subject to change as the project progresses. M. Tudor asked how the employee numbers were determined. John responded that it was activity-based and that a more detailed study will be performed. Meg asked why further study was not being done on hybrid. John indicated it would not be efficient for the team to pursue both options to that level (the critical path for having hybrid in place by 2005 would require work to start by March 2003 and $4 MM to continue hybrid work through August 2003 when the electrification engineering work would be complete). *Id.* In addition, Meg inquired what it would cost to miss the 2005 target for implementation. John said it was hard to quantify. He recommended proceeding with electrification and not pursuing the hybrid case. Meg indicated Conoco was not ready to vote on it. Notwithstanding Conoco's comments, "the Owners agreed to proceed." *Id.*[296] The recommendation was to "stay on schedule for 3Q 2005." *Id.* at 10. M. Drumm emphasized the tightness of the schedule. *Id.* "John noted that it was critical to get things right upfront" and they planned to use peer reviews along the way. K.

[296] *See also* Tr. 4728-29 (Yaege); Exs. SOA-744 at 2; SOA-745 at 2 (hybrid is dead).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Brown suggested coordinating peer reviews with the internal "gate" processes of the Owners. M. Tudor suggested mapping the Owner's internal processes into the team's process. *Id.*

Talking Points

439. In a document with the title "Talking Points for Kevin Myers - Steve Marshall Meeting" the following statement is found: "BP strongly supports moving ahead swiftly and sending Alyeska the message that the owners are united in their position that Re-configuration is absolutely essential for driving major cost improvements in the future." Ex. SOA-472.[297] It continues: "BP respects the ConocoPhillips desire to fully evaluate the "Hybrid Reconfiguration" option (automate but do not replace the Avon Turbines) but believes the cost of preserving that option is too high (~$4mm). Approval of a preliminary engineering AFE in January is critical to maintain project timing." *Id.* This document also discusses reducing the engineering and security staff to obtain cost savings. Security costs would be reduced from $17mm to $12mm or less, engineering can be reduced by 30 people. *Id.* at 1-2.

Email December 12, 2002

440. On December 12, 2002, B. Howitt sent an email to L. N. Motschenbacher detailing an agreement with the State Fire Marshal and JPO on a way forward for a fire safe design process for Reconfiguration. Ex. SOA-670.

Discussion 2002

441. The State argues, the record shows, the economic analysis that the Carriers made for electrification was fundamentally flawed and that a reasonable economic study, consistent with standard industry practices and compliant with the TAPS Carriers own standards would have shown electrification was not justified. State IB 137. Abandonment of their seven years of prior studies for the wholesale replacement of the pumping equipment was imprudent according to the State. The Carriers decision to go forward with electrification was made in February 2002 prior to any conceptual studies. The electrification studies were then preformed in a rushed, superficial manner and incomplete process, or a process designed to justify a decision which had already been made. State IB 137. Additionally, according to the State, the Carriers failed to engage in a detailed analysis and impartial comparison of Electrification with other options as required by their own AFE F180 and standard industry practice. The State maintains that if a reasonable conceptual study had been used, one following the Carriers and industry standard practice, the Carriers would have found that electrification was not economically justified. This flawed process was imprudent the State argues.

[297] This document is not dated. Ex. J-2 dates it to December 12, 2002.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

442. As noted above, during this time frame conceptual studies were done by JTG and GE. Exs. ATC-148 and ATC-147. The studies were completed in three months. This is contrary to industry standard practice for the time frame required for diligent conceptual engineering of a project of this scope and magnitude. The testimony of Sanders in this regard is entitled to significant weight. As he testified conceptual engineering in this case should had lasted up to 16 months. This assumes that prior conceptual scoping studies had been done for Electrification which was not the case. Ex. SOA-425 at 27-28. Contrast the years of conceptual studies for the legacy equipment scoping in 1994 and seven years performing and refining the conceptual engineering. The State is correct that the Carriers' claim that they were able to complete diligent conceptual engineering for electrification (to the level of options using the legacy equipment) by October 2002 is not credible.[298]

443. The electrification engineering studies lacked sufficient detail. As the State points out, a comparison with the prior studies shows what needed to be done. For instance, the prior conceptual engineering studies on automation and controls evidence the process, depth, and detail necessary to support valid cost estimates consistent with Alyeska's project management processes. Ex. SOA-193 at 13 (AMS-003). Additionally, the State is correct that Bailey provides an excellent example of proper studies. For one, Bailey[299] starts with prior studies (1994 study) and it tested the technical feasibility and economic viability of upgrades. [300] The Bailey Report also describes how it developed and tested each of the alternatives,[301] and it describes what the detailed scope of each option would entail to implement.[302] Bailey also provided cost and savings breakdown for each option, having consulted knowledgeable operations personnel and external benchmarking from objective sources.[303] On a system by system basis, the Bailey Report specifically describes what needs to be done for each option, for 24 systems (Enterprise SCADA and Control Room infrastructure to HVAC systems).[304] Moreover, Bailey not only recommended upgrades to the control system, it also recommended elimination of existing defects in the systems (the greater the control system scope of work, the greater

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[298] Ex. SOA-28 at 33, Electrification v. Hybrid Decision document (the scope of the Electrified project is better defined than the hybrid design).

[299] Ex. SOA-135.

[300] *Id.* at 11.

[301] *Id.* at 17-19.

[302] *Id.* at 22-31, 37-49.

[303] *Id.* at 11, 25, 27.

[304] *Id.* at 41-48.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the number of defects that would need to be fixed to assure the benefits are achievable).[305]

444. The Electrification conceptual studies by GE and JTG do not have the key items found in Bailey. As the State avers, neither study explains the process undertaken, describes communications or input from Alyeska operations personnel, detailed comparison of alternatives, or detailed breakdown of either the scope of work or of the top-line cost estimates. The State is correct that these "studies" are generic documents, prepared in three months, lacking in detail regarding how the proposed equipment would be integrated with TAPS. The studies were completed for the cost that has been budgeted for they were very high-level.[306]

445. Conoco questioned the reliance on these studies in December 2002.[307] However, even on the face of the Project Manager (J. Barrett) admission that the analysis relies upon probabilities, which are subject to change as the project progresses" the Carriers continued with the project, even though they were missing specific engineering plans and evaluations like the ones from the previous seven years. *Id.*

446. The State also correctly points out that the electrification conceptual studies lacked buy-in and review by Alyeska operations. F. Adams[308] a State witness testified that internal engineering and operations experts should be included in the planning of projects like SR since they are most familiar with the pipeline and can significantly assist in the planning process. Exs. SOA-275 at 37:20-22; SOA-425 at 36:4-5. Moreover, the Bailey Report noted that Operations was in the team, and in the decision process to review and define the scope of work and ensure they "understood and agreed to benefit estimates." Ex. SOA-135 at 16.

447. Conversely, the GE and JTG reports do not show that knowledgeable individuals were included in the conceptual engineering process. For instance, DeHaas expressed concern that those most knowledgeable were excluded. At the conceptual engineering stage DeHaas wrote: "I find it strange that this project is all about rotating equipment, and from the very concept stage the Alyeska rotating equipment engineer was not involved. Just where did that expertise come from I wonder? . . . Again it is all about rotating equipment, and I've only been asked to review some specs." Ex. SOA-284 at 1-2.

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[305] *Id.* at 25.

[306] Ex. ATC-19 at 52:3-5.

[307] Ex. SOA-299 at 9.

[308] F. Adams has extensive experience concerning large scale pipeline construction projects. He has over 35 years of experience in construction and engineering matters involving more than 300 projects in over 45 countries. Ex. SOA-275 at 20.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Conoco questioned the reliance upon the JTG and GE studies without further engineering. Ex. SOA-299 at 9.

448. As Sanders testified, 'a reasonable manager performs due diligence on each option and compares the options to each other on a fair basis prior to selecting one option over the others. Ex. SOA-542 at 42:20-22. The Carriers did not do this. Further, Sanders testified that the "TAPS Carriers' deeply flawed study of alternatives was unreasonable and contrary to industry practice and standards." Ex. SOA-542 at 14.

449. The evidence in this case shows that on or about February 2002 - prior to conceptual engineering - the SR Team expressed its preference for electrification over the other alternatives. In the February 5, 2002, TAPS Strategic Planning Team Owners Committee Telecom presentation the recommendation was a reinvestment strategy for the pipeline. This was to reinvest in new electric motor driven pump stations. Ex. SOA-451 at 3 or ATC-141 at 3. As Dr. Makholm[309] testified; "[t]he early abandonment of the hybrid alternative made it impossible to reasonably compare electrification to other obviously relevant alternatives. Ex. SOA-547 at 3. Dr. Makholm further testified that the "evaluation of Electrification included errors and biases that the project team did not want to rectify because it ran counter to "preconceived views about the cost advantages of Electrification." He based this observation on evidence that the "[s]taff of the TAPS Carriers complained about the excessive control being exercised by hired vendors" and that "[t]he Staff of Alyeska 'bullied' those who would challenge the initial low cost Electrification cost estimates." Ex. SOA-547 at 3.

450. As Sanders testified:

> A: You're asking me if they did everything wrong. They didn't do everything wrong. They didn't follow what even common sense tell you to do, and that's to take a look at the equipment you've got out there before you go off and replace it. They were looking at that from 1999 until October of 2001. At that time they went off and did- decided they would do full electrification, and all of a sudden, over about a three month period, they adopted that part of the project, not electrification where it made sense, but they were doing full electrification where they saw power plants where they had existing turbines running equipment. And their own people, the rotating equipment engineers and others, said they didn't need to do that. GE, JTG told them the same thing.

Tr. 805-06:9-16.

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[309] Dr. Makholm has many years of experience in regulated utility matters and pipeline issues. He has testified before this Commission and several state public utility commissions on prudence issues. Exs. SOA-525 at 11 and SOA-526 at 3-11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

451. Sanders testified that the "first step in an industry standard approach to a project such as Electrification is to first determine whether there is a need for complete equipment replacement." Ex. SOA-542 at 10. This type of examination would have allowed the Carriers to determine if the legacy equipment was "fit for purpose" under the current TAPS operating conditions and whether this equipment could be successfully used with expected future operating conditions, including future throughput changes. However, the Carriers did not conduct any thorough, independent substantive "fit for purpose" evaluation at the time of sanction, when they authorized the project to proceed.[310] Sanders further testified that the Carriers did not have any third party evaluate this issue. Instead, they

> simply assumed that they were not fit for purpose. Making such an assumption without actual evaluation was unreasonable and not consistent with industry standards especially when the cost of replacement of the legacy pumps and pump drivers with electric equipment was significant and comprises a very large proportion of the total cost of the Strategic Reconfiguration project.

Ex. SOA-542 at 11.

452. Additionally, Sanders testified that he would have done independent studies of the status of the legacy equipment, the piping systems, electrical systems, mechanical systems and instrumentation, and assess the fit for purpose status of the various components and whether they needed to be updated or replaced. *Id.* at 9-10. He did not see any such studies in this record. *Id.* at 19-20. He further stated he would have done condition surveys for the equipment that was at the pump stations and would have looked at obsolescence issues before he decided to dismiss the legacy equipment. Tr. 1327-1328:20-4. *See also* Tr. 1264-65:20-3.[311]

453. In light of the fact that the purpose of the project was cost savings, standard industry practice would have required that the Carriers study in detail whether their existing equipment could be upgraded to secure such benefits. The Carriers ignored a

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[310] Sanders testified that the Carriers should have asked Roll-Royce a number of questions dealing with whether the equipment was fit for purpose and what could be done to upgrade the turbines or control systems. He stated that at the time there were upgrade packages that were available for Rolls-Royce turbines. "That equipment is automated all the time all around the world. He did not see that type of request in this record." "I would have expected to see it." Tr. 937-38:15-3.

[311] The Avons met all applicable air quality standards. "Further, the legacy turbines have always been in compliance with all applicable air quality standards and regulations" and they can be modified to improve their emissions. Ex. SOA-543 at 54; 52.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

study of this issue which had been conducted years earlier. Ex. SOA-542 at 12. Specifically, during the period 1998 - 2000, the Carriers had studied the possibility of automating the legacy equipment. Sanders testified to this stating that the previous study concluded that the "legacy pumping equipment" could be automated through an upgrade of control systems. "The study estimated that automation of the legacy equipment would result in staffing reduction figures that were close to the staff savings projected in Electrification. It also estimated that the cost of automation would be roughly 25% of the cost of Electrification." Ex. SOA-542 at 12. Sanders further testified that

> The TAPS Carriers failure to perform and provide any substantive evaluation of the reasons for the differences in staff savings was unreasonable and was not consistent with industry practice, especially since an earlier study had concluded that automation of the legacy pumps and pump drivers would have achieved about the same personnel savings as Electrification.

Ex. SOA-542 at 13.

454. The SR Team relied on analysis based on probabilities that the team knew were going to change once actual engineering was done. They did not work with Alyeska operations staff and did not work to validate (or invalidate) the previous studies on automation of the legacy equipment. As D. Hisey testified,[312] "when the owner project management team was formed – or when the owner planning team was formed, they set upon a path that clearly defined electrification as the preferred option. And the team created the supporting documents for that." Tr. 3043:22-24. J. Johnson (Pipeline Manager) testified that people were excited about the project, and his belief is that that was part of what overrode some of the belief of the brownfield and some of the hurdles the project had. "Should we have known the larger brownfield aspect? Yes. I think excitement of this project influenced that aspect." Tr. 8439:19-25. He also testified that he did not look at the major studies that had been previously done on the Hybrid option even though he was in charge of creating the maintenance and staff savings numbers for the options. Tr. 8185:25-8186:2, 8187:8-11.

455. The record conclusively establishes that the Hybrid option was dropped from consideration on October 10, 2002, when Kevin Brown wrote that BP would not support Hybrid. "I only wish to mention that BP Pipelines is not interested in continuing to work the hybrid case nor will we support it as a way forward. I am a bit concerned that we

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[312] D. Hisey was the COO of Alyeska from 1999 to August 2005. He was involved with SR from its inception until 2005. One of his responsibilities was to assist with the implementation of the SR project. Thus, this witness is giving first hand knowledge of critical events surrounding the project. In addition he has many years of practical experience with TAPS operations. Ex. AT-230 at iii-iv and 4-5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

weaken our resources working an option that would not have sufficient owner support to proceed." Ex. SOA-180.

456. D. Hisey testified that "BP set the directive in early October that no more work would be done by Alyeska on hybrid." Tr. 3003:7-9. Pomeroy testified that he understood that if BP was not in favor of a proposal it was not going to happen and that if BP did not go forward the hybrid option was dead. Tr. 7932:1-3; 7932 at 13-15.

457. Due to BP's 46.93 percent ownership share it has automatic veto over funding decisions, and its decision on hybrid had the effect of eliminating further consideration of this option. The decision not to consider hybrid further was made before the October 28, 2002 Electrification vs. Hybrid Decision Document. This is contrary to the Carriers' assertions that this document formed the basis of their decision. Carriers IB 91-93. Hisey testified that the Decision Document was merely a justification for a pre-determined outcome. Tr. 3041:24-3042:7. Hisey's testimony in this regard, corroborated by contemporaneous documents is given significant weight. As a matter of fact the record shows that as early as October 2001 and February 2002, electrification was already viewed as the preferred option.

458. BP reiterated in November 2002, that it was ready to go forward with the electrification option. However, Conoco was hesitant. At the time, BP, Exxon and a small third owner had approved the project. Therefore, Conoco's decision did not really matter in the approval process.[313] BP decided not to spend any more money evaluating the hybrid option. Ex. SOA-182. In December 2002, Conoco was still inquiring why further study was not being done on hybrid. Ex. SOA-299. Conoco also questioned how the Owners could rely on the JTG and GE comparisons without further engineering. Ex. SOA-185. This was in response to J. Barrett stating that conceptual engineering is complete. *Id.* However, Conoco was told that it would be inefficient to pursue both options, and work on electrification had to start by March 2003 if it was to be finished in 2005. Ex. SOA-299 at 9. The Owners Committee agreed "not to incur costs related to working the hybrid case any longer even though "Meg stated that PTAI cannot support dropping the "hybrid" case…" Ex. SOA-299 at 4. A. Bolea for BP confirmed that no more money should be spent on hybrid and that he needed "nothing else to decide that BP wants to go ahead with developing electrification." Ex. SOA-466 at 2. Additionally, he stated that the "biggest lever we have to advance projected 2004 savings into 2003 is the early approval of the pump station electrification project." Ex. SOA-184 at 1. Further, one of his priorities was to drive "the electrification project to an early sanction." *Id.* at 2.

459. The 2003 Long Range Plan (LRP) dated October 25, 2002, also shows that hybrid had been dropped by then. The assumptions in the plan are based on electrification. Again this plan was released before the October 2002 Decision Document. Ex. SOA-

[313] Even if Conoco had not approved the project it would still have moved forward having been approved by a two-thirds vote. Tr. 4728:18-4730:3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

181. The LRP states it is based on the "Electrification Reinvestment Strategy" and treats this as the base strategy. *Id.* at 4, 10. The new "pipeline asset strategy is leveraged upon pump station electrification, enhanced controls systems and regional maintenance and OSCP centers." *Id.* at 10. D. Hisey testified that "the direction had been sent that they are going to go with electrification only" well before the October 2002 Decision Document. Tr. 3009:22-24.

460. The value of the 2003 LRP (prepared in October 2002) is limited and will not be given significant weight. First intrinsically it is a projection, with numbers that are not validated or thoroughly studied. They are not tested numbers but projections. Further, the plan and what was undertaken are not the same. For instance, the LRP estimates project completion by 2007 whereas the project was undertaken with a two year completion target. There is no evidence in this case showing that the numbers were estimated again. The plan assumed electrification of PS 12 even though this was not a recommended strategy. Ex. SOA-181 at 104. Most significantly two major issues appear from the LRP first, the industry standard as contemplated in the report is electric drivers where power is available. The report contemplates electrification of PSs 3, 4, 9 and 1. PS 3 and 4 do not have power available. The report contemplated replacing the Avons with smaller electric drivers and this is not the project that was undertaken. The assumptions used zero inflation and increased throughput which are not valid assumptions (especially the throughput which was decreasing). Additionally, the plan itself states that the numbers need further study. For instance, the switching costs needed further study. *Id.* at 127.

461. Of particular significance is the fact that the operating plan for 2003 budget submittal identified 144 maintenance projects (excluding reconfiguration) with an expected cost between $89M to $151 M expense and $44M to $89M capital (without a contingency for major repair work).[314] *Id.*at 91. These numbers are consistent with the financial case without hybrid found on page 123 for 2003. *Id.* at 123. However, there is no explanation of how the major maintenance costs for hybrid were developed. *Id.* Moreover, in the comparison table the same major maintenance expenses are listed for the without hybrid option and reinvestment. However, the hybrid major maintenance is less and the reinvestment major maintenance is slightly over half or the major maintenance for hybrid ($109.8 vs. $55.5). The costs have not been discounted to take into account the time of the costs under the two scenarios which is not a valid assumption if one were to follow the Bailey report (5 years to complete automation of the legacy equipment at $53M). Moreover, at this particular time all studies were conceptual engineering which diminishes the value of all of these numbers. Another interesting issue is the fact that PS1 electricity costs were backed out of the Reinvestment case to

[314] SCADA leak detection upgrade (AFE Z255) was scheduled for completion by spring of 2003. *Id.*at 93.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

"make a more valid comparison since, in the Hybrid case, the natural gas costs associated with generating PS1 power is not reflected in Alyeska's books." *Id.* at 129.

462. Finally, in the 2003 LRP, the engineering was done for totally unmanned stations, which was the alternative rejected in the Bailey Report. Bailey recommended partial unmanning. There are no studies in this record undertaken to contradict the findings of the Bailey report concerning the controls or the findings that electrification was not economic.

463. In addition to all the findings above, concerning the October 28, 2002 Decision Document, Ex. ATC-154 (paragraphs 407 on, *supra*), in the context of all the evidence in this case, this Decision Document is construed as a paper justification for a pre-determined outcome as the State contends.[315] It is found that it did not make a fair comparison of alternatives as required by industry standards and the Owners and Alyseka's own protocols. Hisey testified that the document supported electrification which had already been determined was the "go" option. Tr. 3041:24-3042:7. The State is correct that the October 2002 Decision Document contained a number of assumptions that were unverified and unfairly skewed in favor of electrification. As evidenced by the treatment of Staff savings, 367 positions for electrification and 140 for hybrid. Ex. SOA-161 at 20-21. There is no basis for these projections, there are no back up studies or documentation supporting these numbers. There is no explanation of the significant gap of 200 positions between hybrid and electrification since the savings are attributable to automation and both options had automation upgrades, unmanned operation and use a regional maintenance and oil spill response strategy. Most importantly, it did not explain the discrepancy between these projections and the staff savings projections for hybrid in AFE F180 and other studies. Ex. SOA-153 at 11 (similar Ex. ATC-110). For instance, the March 2000 Strategic Initiatives Report, *supra*, (Ex. ATC-108).

464. The Carriers knew the deficiencies in this decision document. Conoco's P. Flood expressed concern with the accuracy of the document the day after he received it. Exs. SOA-495 or ATC-155. As discussed above, P. Flood notes that the Appendix B totals for hybrid are incorrect, the values do not add up. *Id.* He is concerned that there was insufficient time for QC and a review is in order. Ex. SOA- 495. Flood attached an excel workbook (projects avoided with electrification) to his email. EX SOA-496. In the workbook there are several notations where he questions whether the scope/cost is too high for hybrid and one inertia projects spreadsheet states "WHY IS THIS THE SAME AS FOR HYBRID? Is this not real? *Id.* at 16.[316]

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[315] The Carriers in reply admit that "the Decision Document did not have the technical detail of any of the prior studies." Carriers RB 38 n. 53.

[316] Note that the email shows an excel spreadsheets titled Projects Avoided with Electrification. Ex. SOA-495 at 2. However, the attachment is not in the exhibit. On the other hand, Ex. SOA-496 which includes a tab "Project Avoided w Elect" is undated.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

465. Additionally, the person heading the team that put together the October 2002 Decision Document staffing numbers conceded he did not read the previous reports (Bailey or Kenonics) that detailed the level of automation and the proposed corrections to defects in the system that would be provided through hybrid. He did not know the upgrades to the system recommended by Bailey. Tr. 8195:8-10. Moreover, he did not consult manufacturers of automation systems to determine their capabilities. Tr. 8232:23-8233:1. Further, he did not consult anyone with experience using modern automation systems and did not even know who these people were. Tr. 8232:17-20. Conversely, Dr. Sanders testified, that common sense and industry practice require consultation with the original manufacturer of the legacy equipment … to seek information on options for upgrading it and to determine whether it could be used to meet their needs. Ex. SOA-542 at 46:4-8. This Sanders testimony is given significant weight.

466. Howitt testified that J. Johnson began his evaluation of staffing under hybrid and electrification in August 2002.[317] Tr. 6783:5-17. Johnson confirmed this and stated his belief that this was the first detailed operations staff involvement in the project. Tr. 8185:7-10. According to Johnson, it took him about seven weeks to complete his analysis working part-time since he had other primary responsibilities. Tr. 8245:10-13. He spent about one-third up to one half of his time on the analysis for the SR Project. Tr. 8261:18-23. The record shows his due diligence was minimal. He did not know the ancillary equipment needed to run the turbines, VFDs and generators. Tr. 8219:8-11. Additionally, he did not see any detailed engineering documents of any of the SR mainline units prior to doing his staffing analysis. Tr. 8302:9-14. As a result, he could not do the "RCM" process to ascertain the future maintenance required after SR. Tr. 8302:15-22. Nor did he know the detail of the devices that were to be added to existing equipment to automate TAPS. Ex. SOA-743 at 3. He "staffed to a concept." Tr. 8303:19-22. He assumed a "good share of the buildings would go out of service with electrification." Tr. 8209:6-7. He knew that maintenance work is needed on all of the subsystems and utility systems that are needed to support that system. Tr. 8452:18-20. His assumption was that if buildings and systems were eliminated, then maintenance work would decrease and with it the need for staffing. Tr. 8515:7-21. He did not read the Bailey or the Kenonic Reports. Tr. 8228:20-25. He had no experience with automated systems. Tr. 8233:12-14.

467. Johnson testified he was not involved in the Electrification vs. Hybrid document. Tr. 8244:18-20. According to Johnson, Howitt and Pomeroy were "pushing the envelope in terms of their staffing analysis for SR or looking for the maximum number of staff

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The chronology, Ex. J-2, dates this exhibit as of June 9, 2003. It is deemed for purposes of this decision that Ex. SOA-496 was the attached documentation.

[317] Howitt confirmed he did not make any substantive decisions in that process. Tr. 6783:18-20.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

reductions possible." Tr. 8271:24-8272:3; Tr. 8494:21-8497:4. The excitement about the project clouded the Carriers vision. Tr. 8462:4-5.; Tr. 8274:17-23; Tr. 8461:20-22. Johnson developed his projections based upon the minimal conceptual engineering at the time. This engineering lacked scope and was inadequate. Ex. AT-405 at 15. Consequently, the staffing levels were premature and could not be completed until Alyeska determined what was being built or how it would be operated and maintained.

468. Johnson testified that electrification would have reduced 367 people by 2008. Hybrid would have reduced 140 people by 2008. Ex. ATC-891 at 17. Citing ATC-895 at 3 and ATC-896 at 3. According to Johnson, the difference in the lower hybrid number is that he did not credit any staff reductions for hybrid at PS3. Note that from February to October 2002 the staffing changes for hybrid have been reduced to 140. Ex. ATC-141 at 12 (206 staff reductions with Hybrid) and ATC-893 at 3 (210 reductions with Hybrid). The electrification numbers changed also. In February 2002, the projected reductions for electrification were 240 positions (Ex. ATC-141 at 12). In October Johnson increased this number to 367. Ex. ATC-891 at 13:15.

469. The reduction for hybrid is a 53%. Compared to AFE F180 the staff reductions for hybrid are significant. For instance in the base case in AFE F180 the staff reductions were 180 and for case 3 the staff reductions were 265. Johnson reduced these numbers by 23% and 47% respectively. Ex. ATC-110 at10-11. The only conclusion that can be made is that the numbers were changed without any further engineering studies to make the electrification option more favorable. The new staffing reduction numbers for hybrid are in total contravention to the numbers that had been the result of years of study of automation without similar support. Johnson's testimony in this regard is not entitled to any weight. He testified he had no experience with the automation and predictive maintenance systems that would be installed on the pipeline nor did he consult experts on the matter in reaching his numbers. Tr. 8233:12-14 and 8206:5-8208:20.

470. D. Hisey testified that to determine staffing levels with any reliability, first you have to define the operating context and conduct Reliability Centered Maintenance (RCM) analysis. AT-405 at 12:11-13. Alyeska defines that operating context and uses the RCM analysis to establish maintenance strategies. This approach provides for a complete understanding of the specific equipment systems and processes to be maintained. D. Hisey goes on to testify that without this analysis, the analysis of staffing needs based upon conceptual engineering is largely speculation. *Id.*

471. Turnipseed[318] confirmed that the SR design documents were "very, very conceptual, very, very high level. Ex. AT-429 at 14. He also stated that what was seen in this case was a conceptual study that moved immediately to construction. He also states that had "the quality program been followed, we would have seen a conceptual

[318] Turnipseed has been with Alyeska since 1978, on the SR project since early 2005 and is a highly respected maintenance expert on TAPS. Ex. AT-405 at 7.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

study, we would have seen an issue for review, we would have evaluated the issue for review, and we would have seen an issue for construction." AT-429 at 33.

472. The Carriers argue that ATC-141 shows the hybrid strategy results in 266 positions or a reduction of 206 positions.[319] However, ATC-141 at 12 shows the 266 number as being tied to the Flywheel (w/o additional storage) there is no indication in this exhibit how flywheel (w/o additional storage) became hybrid. Page 10 refers to Flywheel, Inertia, Middle, Minimum, Hybrid and Re-Investment comparing service factors. Page 11 compares inertia to hybrid for the assumption that manned and virtually unmanned approaches yield high service factors. Note that these names have their genesis in ATC-135 and there was no mention of hybrid back in 2001. On page 12 of ATC-141 in the "Savings" section "Hybrid" appears at the end column showing savings. It is noted that this section also shows "Flywheel." Ex. ATC-141 at 12.

473. The Carriers submitted an undated document as underlying spreadsheet for the alleged staff reductions. It is noted that the current staff number is 466 ("Staff Levels Today") whereas ATC-141 states it is 472 ("Staff Today"). Ex. ATC-904.[320] An unexplained 6 person reduction between the documents.[321] Pomeroy testified that most of the difference in the staffing levels between hybrid and electrification is the result of the assumption of more equipment for hybrid which is more complex.[322] The Carriers allude to benchmarking studies. Carriers IB 31. However, these studies are not part of the record in this proceeding. It is noted that based on the proposals as known at the time the de-manning options for hybrid and electrification were not the same. Hybrid as the Carriers have described it in their brief, was enhanced automation for unmanned operations, electrification was full automation for maintenance also. At the close of this

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[319] Ex. ATC-141, *supra*, is a February 5, 2002 Owners Committee telecom.

[320] Ex. ATC-904 is an undated document. The Joint Chronology dates it as January 22, 2002. Ex. J-2 at 5.

[321] In ATC-904 at 8, the numbers for Inertia match the numbers in ATC-141 at 12. The same is the case for "Minimum" at 10. However, for storage there is an 8 person discrepancy (page 12) between exhibits. The same is the case for "Mid-Sized" at page 14. The number for "Recapitalization" is significantly reduced by 15 more persons. "Flywheel with no storage" shows 8 people more than Ex. ATC-141 at 12. It is noted that Ex. ATC-904 which the Carriers claim is the spreadsheet documenting the estimated staffing levels for each of the options under consideration does not mention hybrid at all. Carriers IB 30. The Carriers admit that the numbers are similar but not identical to the February 5, 2002 presentation. According to the Carriers the numbers in Ex. ATC-904 are based on analysis up to January 22, 2002. This still does not explain the numbers discrepancy.

[322] Ex. ATC-898 at 32.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

record there is no clear definition of hybrid in the supporting material.[323] The supporting documents Ex. ATC-141 shows Flywheel without storage and hybrid. However, the alleged supporting spreadsheet, Ex. ATC-904, shows Flywheel with no storage and no hybrid. Thus, the comparisons of hybrid and electrification staffing reductions are not given significant weight. Likewise, no credit is given to the costs reductions since analysis of ATC-135 and ATC-141 *in pari materia* leads to the conclusion that Flywheel would require "relatively lower skilled, lower pay workforce, larger number."[324] Whereas, the Re-Investment strategy required "relatively higher skilled, higher paid workforce, lower in number."[325] The record is devoid of any attempt to reconcile these statements. It is also noted that while exhibit ATC-141 at 12 shows 240 staff reductions with recapitalization previously in December 2001 it was 270 (Ex. ATC-138 at 49). The record shows that at this time frame, December 2001, North Slope Storage was renamed Flywheel and Re-Investment was "now with new pump stations." Ex. ATC-138 at 5.

474. The Carriers claim that the Decision Document had sufficient detail relating to the relative costs and benefits of each alternative. Carriers RB 38, n. 53. However, as shown above, the details of the document were skewed and further it was based on invalid assumptions. Thus, reliance on this document was not the act of a reasonable utility manager. The Carriers again try to reinvent history by analyzing an October 9, 2002, email to reply to arguments made by the State. The fact is that on October 10 (notwithstanding the diatribe of how much information the Carriers needed for a decision in the email dated October 9) K. Brown, Vice President, BP Pipelines responded that "BP Pipelines is not interested in continuing to work the hybrid case nor will we support it as a way forward." It gets better then he states: "I am a bit concerned that we weaken our resources working an option that would not have sufficient owner support to proceed." Ex. SOA-180. The October 28, 2002 electrification vs. hybrid document recommends electrification and is thus congruent with the October 10 email.

475. The Carriers also emphasize Ex. ATC-905 in support of the credibility of their witness Pomeroy claiming that he did not have a predetermined outcome in mind. However, a careful reading of this document does not support the Carriers' statements. In the document Pomeroy was in favor of "highly credible alternatives" . . . This would require that we continue to modify the assumptions around the current operation as we develop the electrification project. The inference being that they were "developing the

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[323] AFE S020 does define hybrid as "assumes control system upgrades allowing pump stations to be partially unstaffed, and other lifecycle maintenance and replacement as required." Rovers would continue to observe pump station equipment operated by the OCC. Ex. SOA-60 at 11. However, there is no explanation in Ex. ATC-141 that this were the assumptions followed.

[324] Ex. ATC-135 at 20.

[325] *Id.* at 21.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

electrification project" and creating "highly credible alternatives" in other words, electrification was a "fait accompli" and they were just creating "alternatives."

476. Sanders was very critical of the electrification versus hybrid decision document Ex. SOA-28. He states that it "appears that the selection of Electrification was preordained." Ex. SOA-542 at 46 (citing Ex. SOA-425 at 41, 43, 62). He stated that it was not a proper review of the alternatives. "The comparison was never at a level of detail and fairness consistent with industry practice." Further, he testified that it was not "a dispassionate study of alternatives." Additionally, Sanders testified that all the way through the preliminary engineering there was not adequate comparison given to the hybrid option. Tr. 1039:42:14-4. He further testified that the earlier studies

> [a]ttested to the excellent condition and maintainability of the existing equipment then and going forward, and these studies supported its retention over new, electrified equipment. In addition, these studies also showed that the legacy equipment could be automated to obtain the reduced manpower benefits expected of electrification at a much lower cost. But when electrification was considered, the findings of these studies were not factored into the analysis. This is contrary to reasonable industry practice.

Ex. SOA-542 at 43.

477. The Carriers did not acknowledge, much less rebut, the conclusions of the previous studies. Sanders stated:

> These study efforts were performed by personnel that included knowledgeable and experienced pipeline operating personnel from Alyeska that were familiar with the regulatory environment in Alaska with respect TAPS . . . Risks were evaluated in a careful program of logical and manageable change to the system were proposed in all cases. Moreover, the conclusions in these studies were in effect validated by the comments of Alyeska's own engineering personnel. The failure to consider these studies as part of the overall analysis of Electrification and analyze why entirely different conclusions were reached was not reasonable.

Ex. SOA-542 at 45.

478. Anadarko argues that SR was poorly conceived and fundamentally flawed from inception. Anadarko IB 2-3. It avers that the Carriers failed to show a single example in the world where a pipeline operator installed electric MLUs at remote pump stations. Tr. 8101:10-16 and 8252:10-8254:1. Anadarko is correct that the record in this proceeding shows that pipeline operators have prudently chosen to install electric MLUs only when there is a reliable public electric grid to provide electric power. Anadarko is also correct that in the 1970s the Carriers faced with the choice of how best to operate the same remote pump stations, during the original construction of TAPS, chose direct-drive fuel

20140227-3052 FERC PDF (Unofficial) 02/27/2014

turbines. Further, studies during the 1990s dealing with the same issue upon examining all alternatives, including electrification of MLUs with potential access to the grid, electrification of the MLUs was not the chosen alternative and the alternative chosen was to continue to use the existing direct-drive fuel turbine MLUs. Ex. ATC-105 at 8-10 and 21. Additionally, BP chose direct-drive fuel turbines when faced with the same options in Europe during the same time frame as the SR project.[326] In the words of the most knowledgeable rotating engineer at Alyeska, concerning the leadership of the SR project, it "was led by a bunch of complete and total idiots..." Ex. AT-449. Anadarko avers that the decision to install electrical MLUs at remote pump stations was an incompetent decision (not just imprudent).

479. Concerning the "clean slate" Anadarko argues that the Carriers did not have a clean slate and were not building TAPS new today. Anadarko IB 3. Instead, they had reliable and robust direct-drive fuel turbine MLUs that could continue to provide service throughout the entire planning horizon for the SR project. The reliability of the direct-drive fuel turbines was so good that unscheduled shut downs were rare. Exs. ATC-898 at 8 and ATC-154 at 31. Additionally, Anadarko states that taking out robust and reliable direct-drive fuel turbine MLUs to install electric ones was foolhardy.

480. The SR project was an optional project designed to lower operating costs.[327] Pomeroy a member of the Owner's Strategic Planning team, responsible for preparing the electrification versus hybrid document, confirmed that the legacy equipment was well maintained, and highly reliable, with low failure rates and low unplanned shutdowns. Tr. 7833:8-14; 7980:17-19; 7981:2; 7980:15-7981:3; 7985:11-23. Howitt[328] testified that the pipeline was reliable and that the sole driver for SR was cost savings. Tr. 4604:8-13.[329]

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[326] In a visit to the Forties Pipeline in Scotland, the Carriers observed electric MLUs installed only when a public electric grid with two redundant sources of electrical generation was available to supply electric power. Tr. 8099:15-25.

[327] The following Carrier witnesses confirmed that the decision to undertake SR was purely economics. (Barrett) Ex. ATC-24 at 32 and (Tudor) ATC-27 at 10. Additionally, Hisey confirmed this. Ex. AT-230 at 6; Tr. 3052:15-16; 3015:14-3016:6; 3276:13-21 and 3900:5-21. Hisey testifying that SR was driven by economics. Tr. 3052:15-16.

[328] Howitt was the Senior Executive Advisor to Alyeska's COO and CEO with respect to the SR and the liaison between operations and the SR PMT. Ex. ATC-19 at 3.

[329] Tr. 4779:16-17 (Yaege testified that the project was driven by the desire to reduce costs); Ex. ATC-18 at 12 (Ray testified that SR was undertaken to change the cost structure of TAPS and better position it for future cost-effective operations as throughput declined); *Id.* at 47 (Ray testified SR would reduce cost of service); Ex. ATC-20 at 23 (Rabinow testified that the goal of SR was to provide 30 years of efficient and economical service).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Hisey testified that the SR projects was not the result of the condition of the existing pumps and turbines. The legacy equipment was going to be automated that was always an option. Trying to characterize the legacy equipment as being old, run down, out of date, and ready to shut down is false. Tr. 3014:19-3015:5. Moreover, recently an Avon was placed in service at PS 7 for recirculation to add heat. Tr. 4407:21-4408:2. The legacy equipment had sufficient spare parts.[330] Exs. SOA-19 at 2; SOA-21. As a matter of fact, PS 1 currently operates with legacy pumps and turbines. Tr.3015:5-6 and 3905:8-22.[331]

481. In 1999 VECO reported that the legacy equipment was not obsolete and could be maintained "virtually indefinitely." Ex. SOA-134 at 8. In 2002, GE confirmed that Alyeska's experience with the legacy equipment has been excellent. Experiencing high efficiency with little decline during the past 25 years. The pumps are rugged and durable. Ex. SOA-17 at 16. Moreover, the JPO in 2002 concluded that the SCADA system was "reliable and robust" and had a virtually unlimited life" and would "continue to meet all operational requirements for the foreseeable future. Ex. SOA-18 at 45-46. In 2002 DeHaas reported that the Avons had many spare units, with no immediate obsolescence issues and will continue to be serviceable for many years into the future, there will be some obsolescence issues on the instrument side at some point, but nothing major and the Cooper RT's were "essentially infinite life machines" with very large stock of RT spare parts in inventory, the cost of maintaining them is minimal. With regard to the MLUs he stated that they are essentially infinite life, there are no obsolescence issues with spare parts. He opined that replacement pumps would not be as robust and reliable as the present units and the remaining control systems will remain viable and operable for several years. Ex. SOA-21. DeHaas did not agree that the legacy equipment should be replaced and there would be no benefits to replacing the equipment. Ex. SOA-19.

482. Additionally, Alyeska reported that "the major mechanical equipment is operating extremely well. Reliability is very high[332] and unplanned shutdowns are rare. It is working so well that maintenance personnel are not retaining their skills in tasks such as changing mainline pump seals. Ex. ATC-154 at 31. Carriers witness Howitt testified that the operating condition of the turbines and pumps in 2001-2003 was not in serious

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[330] The legacy equipment was efficient, reliable and robust. Ex. SOA-19 at 2; SOA-21. The maintenance costs for the legacy equipment had been decreasing. Ex. SOA-19. There was a large inventory of spare parts. Ex. SOA-429 at 15, 24-25; Ex. SOA-431 at 245-46. The decommissioned equipment could be used to replace legacy equipment as needed. Ex. SOA-19 at 2.

[331] As a matter of fact, Barrett confirmed that at sanction of SR the Carriers did not know the source of power for PS1. Tr. 5800:8-22.

[332] An Exxon document indicates that from 1995-2001 TAPS had an average 99 percent reliability. Ex. SOA-263.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

question, the MLUs and turbines "were reliable and could have continued to be used for some time to come." Ex. ATC-19 at 109, 111. Howitt also confirmed that the Avons would not need to be replaced in the next 20 years due to degradation or obsolescence. *Id.* at 104.

483. Hisey testified as follows concerning the reliability of the legacy pumps and turbines:

> [W]e had no indication that they were or that they would [fail], they were only 25 years old, 25 years in the life of a gas-driven turbine generator is not that long. They last much longer than that, 50, 60 years. The depreciation is much greater than that. These systems, these MLUs are maintained, it's a world-class organization that Alyeska has, a world-class maintenance monitoring and repair and rebuilds of those systems. You would not have 99.997 percent reliability for 25 years if you didn't have extremely reliable equipment. That's what Alyeska had. It was maintained at a superb level. It was capable of being maintained at that level indefinitely. We've always said at Alyeska the system is maintained—maintainable indefinitely. Control systems electronics, yeah, you've got to update those because electronics change fast. Turbine generators, they are what they are. They've been that for like she said, 40, 50 years. The technology has changed some, but there's big, robust industrial pieces of equipment that can last a long time. Alyeska had plans and recommendations to automate control systems, update their business management process systems, live computer systems, live telecommunications systems, potentially build a new SCADA system and build a new control center. Those were technological updates, Alyeska agreed needed to be taken and that would deliver significant cost savings. Alyeska did not see in '94 to 2000 a need or any sort of economic justification around replacing main line units. It didn't exist. There were too many spares and too much reliability, and they were operating extremely well.

Tr. 2964-65.

484. In addition, he testified that "I also recall there were a lot of engineers who thought they could maintain these things indefinitely, that they were running fine, had been running fine for 25 years, they had been maintained at the peak of performance. So as far as MLUs are concerned, it just takes maintenance and overhauls and rebuilds and stuff that's routine to Alyeska." Tr. 3061:18-24. Hisey stated that after "25 years, Alyeska considered the equipment extremely reliable, it always operated 99-plus percent reliability, continued to operate at that reliability, and there was a bunch of spare units left. We had a lot of spares in the system … So the Alyeska position had always been we know these Avons, we know the MLUs. They work extremely well, and we have a bunch

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of spares." Tr. 2962:16-24, 3999:15-4000:16. Rabinow, President of Exxon testified that the pumps, valves etc, had been well-maintained and had considerable useful life. Ex. ATC-20 at 7:8-9. For instance, PS 1 is still operating with legacy equipment. Tr. 3015:5-6; 3014:14-3015:17.

485. Anadarko is correct that there were spare parts for the legacy equipment and the cost of repair did not justify replacement. There is a workforce in place to service this equipment. Ex. SOA-596.

486. BP had veto power over any project. Ex. AT-8 and AT-243 at 4. It decided to focus on replacing the legacy equipment with new electric motors when minimal analysis of electrification had been done (April 2002). *See* Ex. SOA-179.

487. The Carriers attempt to justify SR as a way to reduce operating expenses through capital investment. The reduction in operating expenses was the result of personnel reductions and the avoidance of major maintenance projects. Ex. ATC-917 at 33. The record reflects that SR was a discretionary project. Ex. ATC-898 at 11-12. The Carriers assumed operating and maintenance costs savings as a result of electrification. The premise was that they were going to use excess Prudhoe Bay electrical power as well as installing additional generation capacity at the Prudhoe Bay electrical generating station. Ex. SOA-471. They also assumed that the project could be completed in 3-5 years. *Id.* Both of these assumptions were wrong and were inconsistent with the actions of a reasonable utility manager.

488. GE's study assumed that the electrical pumping facilities would be in "equipment modules" that would be "truck-able and pre-assembled at the factory." Ex. ATC-147 at 267. It also assumed that the modules would be pre-wired, minimizing "site construction and field connections." GE further assumed that modules would be designed for maintenance with panel door access but would not accommodate continuous presence of personnel. *Id.* As a result, GE's study did not attempt to resolve any of the integration issues identified in prior studies involving all other utilities, equipment, and facilities necessary to operate TAPS. Moreover, it did not resolve the issues of which buildings would need to be retained due to required equipment or the fire and gas suppression issues with the Fire Marshall. In essence, what GE studied is how to replace the Avon/Cooper pump drivers with electric GE pump drivers. JTG did an identical study for comparison purposes and their costs were within 10 percent of each other. Ex. ATC-19 at 52.

489. The PMT assumed that electrification would solve the Fire Marshal compliance order. This was not supported by any studies. The underlying assumption was that PS 3, 4 and 9 would have all facilities replaced by engineering truckable modules constructed off-site. Ex. ATC-147 at 267. This record does not show that any studies were done to support the assumption. This unproved assumption impacted the decision to accelerate the schedule and led to unrealistic cost and benefits for electrification.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

490. Anadarko is correct that the Carriers did no other due diligence or appropriate benchmarking to ascertain if any other pipeline company had ever done what the Carriers were determined to do. Pomeroy confirmed that the only benchmarking he did was look at BP's Forties Pipeline and they were simply sight visits. Tr. 8023:3-8025:3. No reports were done (except expense records). The Forties pipeline used electric drives at two pump stations and had legacy equipment of similar vintage as TAPS. Pomeroy testified that the Forties pipeline brought in commercial electric power from redundant grid sources. Tr. 8024:4-14. He confirmed that they did not "make their own electric power." Tr. 8059:3-6. Forties did not need a generator to generate electricity. Tr. 8075:3-8076:5. Further, he distinguished Forties from TAPS since it does not have the same infrastructure (Forties does not have relief tanks, manifold buildings, liquid fuel tanks, compression buildings, booster pumps buildings, pig launchers, and elevated piping racks. Tr. 8075:3-8076:5. Pomeroy testified that other pipelines transitioning from gas turbines to electric turbines were not examined. Tr. 8073:17-21. The Carriers were given this information. Tr. 8073:3-6. Additionally, Pomeroy was not aware of any other pipelines that had been converted from gas-powered pump drivers to electric-powered pump drivers. Tr. 8066:19-22. He did not visit pumps with unmanned gas turbines. Tr. 8073:20-22. Johnson[333] also testified that he was not aware of anywhere in the world where pipelines had converted from gas powered pump drivers to electric powered pump drivers. Tr. 8251:9-12. Additionally, he testified he was not aware of any pipeline in the lower 48 that operates electric pumps when it is remote and off the grid. Tr. 8253:18-22. Thus, Anadarko is correct that the benchmarking was not that of a reasonable utility manager.

491. Additionally, the Carriers did not study the "infant mortality" issues of the new equipment. Tr. 8026:19-23. A reasonable utility manager would have looked at the "infant mortality" issues before replacing reliable equipment. As a result, they did not know the likelihood of the new equipment breaking down shortly after startup. Further, the Carriers did not address the inefficiency of converting gas power to electricity to run an electric motor. Tr. 8059:7-19. Pomeroy also testified that he did not know the efficiency of the Siemens turbines. Tr. 8079:22-8080:1.

Conclusions 2002

492. As soon as BP decided not to continue development of the hybrid case, *de facto*, it became impossible for the other Carriers to continue looking at hybrid as an option. BP was necessary to fund the project. Ex. SOA-160 at 2. By October 2002 the LRP treats

[333] Johnson was the Pipeline Manager from 2002-2005 and became Vice President in 2005. He reported to G. Jones who reported to D. Hisey. Ex. ATC-891 at 2. Johnson's team was responsible for developing the projected savings form the SR project.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

electrification as the base case. "Therefore, the new pipeline asset strategy is leveraged upon pump station electrification, enhanced control systems, and regional maintenance and OSCP centers." Ex. SOA-181 at 10.

493. It is concluded that the Carriers knew that they wanted to reinvest in the pipeline. In February 2002 this would entail electrifying the pumps for pump stations and ROW maintenance reduction from 472 to 232 or a 240 personnel reduction and a savings of $25,042,000. Ex. ATC-141 at 12. This exhibit also shows that the projected savings comparing inertia to hybrid is $16 million and the delta from hybrid to reinvestment is $12 million.

494. Further, by February 2002, three months after the "clean sheet" approach, the SRPT recommends electrification. Ex. SOA-451 at 3. There are no studies to support this recommendation.[334] Moreover, there are no studies contradicting the previous studies' conclusions or why they were rejected.[335] The Carriers in their initial brief argue that electrification was the standard in the industry citing Rabinow's testimony. Carriers IB 28. This witness' testimony in this regard is not given any weight. There is no evidence in this record to support this statement. Further, Rabinow was not qualified as an expert on pump station industry standards.

495. The same can be said for the Carriers statement that it was inefficient and costly to operate the legacy equipment at the reduced throughput levels citing the testimony of Ray, Howitt and Rabinow. Carriers IB 17. First, the cited testimony does not support the statement in the brief. Further, there is no evidence in this record to support this statement. Moreover, these witnesses do not cite to any engineering studies to support this statement. The Carriers IB 29 also states that "the Team combined the previous existing-facilities strategies to produce a new one designed to identify the greatest level of staff reduction . . . This was referred to as "optimization of the base case." They cite exhibit ATC-138 at 9. However, this exhibit does not support the Carriers' assertion that hybrid was the optimization of the base case. The record also does not support the Carriers' assertion that the previous strategies were combined to produce a new one designed to identify the greatest level of staff reductions. On the contrary, the record supports that North Slope was changed to Flywheel. See descriptions above. Nowhere in Exhibits ATC-135 or ATC-138 is the word hybrid mentioned. Pomeroy's testimony in

[334] The only evidence are two PowerPoint presentations without any technical backup or explanation and no risk analysis of electrification. Ex. ATC-138; SOA-451. P. Flood testified that a comprehensive assessment of the risks of electrification was not done until preparation for the sanction or the AFE sanction period. Tr. 5476:8-10.

[335] For instance, the previous finding that electrification would have higher technical risks because it represents a significant change in equipment and adds dependence on the utility. Ex. SOA-143 at 16 (Reinvestment Strategy Study Jan, 18, 1999).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

this regard is not given any weight. As the Carriers admit, Flywheel included increasing the crude oil storage tankage on the North Slope and sufficient automation to allow de-manning of the pump stations except for PS1. Hybrid did not include the storage facility. Additionally, the Carriers state that hybrid was similar to the "mid-size" strategy. However, mid-sized contemplated continued manning of the pump stations at reduced levels.

496. The Carriers assert that the relevant inquiry "when investment decisions are at issue . . . is on the company's decision making process." Carriers IB 87. They assert that the questions to be resolved are whether management took the steps reasonably necessary to make an informed decision citing *New England*; whether management reasonably considered ratepayers concerns citing *Iroquois;* and whether management reasonably weighed the risks versus the rewards of the project citing *Kentucky Utilities Company*. In addition, they contend that when project management is at issue, the principal questions are whether a reasonable process was put into place by management, and whether management responded reasonably based on the facts and circumstances as they developed citing *Conn. Yankee*. As demonstrated below, looking at the evidence in this case in the light most favorable to the Carriers it can only be concluded that they did not act reasonably and did not act like similarly situated managers in the industry would act.

497. The conceptual engineering for electrification had a 36 month implementation deadline. The Carriers knew that others including previous automation studies required 4-5 years to implement. Further, they knew that the study was for more throughput than was projected at the time. The cost estimates were geared for off-site construction with roughly 30% being on-site. The conceptual engineering studies for electrification were done in two months. The Carriers knew as shown above, that Alyeska had studied automation for years. The Carriers also knew that the GE report studied the MLU replacement in a static environment eliminating variables, such as declining throughput. They knew that gas was virtually free in Alaska. They knew that GE stated that the legacy pumps were operated at variable speeds with excellent reliability and off the charts efficiency. They also knew that credible employees were stating the costs estimates for electrification were low. They also knew that they decided to proceed with preliminary engineering of electrification without further studying the hybrid option based on economic analysis which were suspect.[336] The basis for this finding is that the numbers for staff reductions for hybrid were purposely lowered inconsistent with prior studies. Moreover, they knew that the schedule was "aggressive," with zero float, no contingencies and required flawless execution. The State is correct that the conceptual engineering process was contrary to prudent management, the decision to go forward was

[336] At a minimum (assuming *arguendo,* one was to give any weight to the cost estimates), they knew the cost estimates were "order of magnitude" solely for comparison purposes with no contingencies. A prudent manager would have questioned these estimates.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

rushed, excluded the most knowledgeable personnel, relied on unsubstantiated assumptions, and was geared to justify a course that was decided before the creation of the decision document.

498. They also knew that VECO had stated the automation project would last four years from preliminary engineering to implementation. Ex. SOA-134 at 31. Anadarko is correct, that considering that Alyeska had already invested two to three years in developing the conceptual engineering the automation project was really a seven to eight year project.[337] Therefore, it is concluded that the Carriers knew that the 22 month schedule for the SR project was unrealistic and therefore they should have known that this was indicative of a project where the scope has not been sufficiently developed.

499. As Anadarko correctly points out,[338] the electrification proposal ignored the detailed conceptual engineering of the Bailey Report on automation and control systems. The electrification proposal assumed that electrification would eliminate the need for regulatory approval of the fire and gas suppression modifications, would provide additional heating for crude, and would provide additional "turndown" capacity. As discussed below, none of these benefits came to fruition. Further, the Carriers assumed that virtually all of the TAPS infrastructure would be replaced by truckable modules. This record does not contain any evidence that this assumption was validated by any engineering analysis. This is not the action of a reasonable utility manager.

500. The Electrification vs. Hybrid Decision Document assumed the availability of utility power supply at PS1. Ex. SOA-28 at 9. The Carriers also assumed that the modular construction of electrical pump drivers would replace pump station buildings thus eliminating the fire and gas suppression issues identified by the Fire Marshal. *Id.* at 10. There is no evidence in this record that the State Fire Marshall agreed to this. The Carriers also assumed that electrification would "significantly reduce the installed infrastructure at the pump stations and simplify many systems. *Id.* at 12. This was unsupported by any study of the existing infrastructure. As discussed below, both assumptions proved to be wrong.

501. The Carriers knew the project was rushed and as a result they knew they omitted steps in their own processes. Exxon prematurely approved the project at Gate 3, rather than completing the project development lifecycle through Gate 4. [339] The expedited project schedule required a "[n]on-typical funding strategy . . . to meet 2005 start-up"[340]

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[337] Anadarko IB 56.

[338] Anadarko IB 64.

[339] Ex. SOA-261 at 1-2 (Exxon's Gate 3 and 4 funding requirements to approve the project); Ex. SOA-286 at 2.

[340] Ex. SOA-232 at 7.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

and caused "gate review activities to converge." Ex. SOA-232 at 7. Moreover, as will be established below, the Carriers failed to follow the typical stages of conceptual, preliminary and final design engineering and then implementation. They started construction before engineering was complete. These are not the actions of reasonable utility managers.

502. J. Barret was hired on October 7, 2002 as Program Manager for SR. Tr. 5658:10-13. He testified he was hired to implement the electrification project. Tr. 5660:6-9. The largest project Barrett had previously managed was the South Pass project which involved installing two miles of a 6-inch pipe at a total cost of less than $2 million.[341] Ex. ATC-24 at 2:11-16. Tr. 5708:8-10; 5705:14-5708:10; 5859:24-5862:17; 5865:3-5866:19. It is concluded that this action by the Carriers is preposterous. It is concluded, despite the Carriers arguments to the contrary,[342] that the Carriers knew that this manager had not had pertinent experience with projects as large as SR. As the State points out, the Carriers have not tried to explain how this limited experience was sufficient to prepare Barrett to manage a project that was at least 125 times as large (using the unreliably low original sanction estimate) for an 800 mile, 48-inch diameter, pipeline, requiring work on four operating pump stations and a fifth relief station. State's RB 22. Moreover, companies such as the ones involved in this case must have had more than enough amply qualified people to hire to manage the SR project.

503. J. Barrett testified that shortly after he became Program Manager, he pointed out the tight schedule to the owners. "Once we had a chance to take a look at it and put some of the parts and pieces together to see how it might be executed between then and the end of 2005, it was our opinion it was going to be very difficult to do." Tr. 5663:12-16. He also testified that he pointed out to the owners that the project had zero float, that it required flawless execution. Tr. 5806:1-6. Barrett testified that despite his concerns the schedule was not changed. Tr. 5663:23-25.

504. Barrett further testified that he understood Hybrid could not be approved if BP did not support it. Tr. 5662:16-21. TAPS ownership structure and agreement requires BP agreement for a project to go forward. Meg Yaege testified that the structure of decision making on TAPS is that 66 and two-thirds and at least three owners need to approve the SR project. Tr. 4729. BP has veto authority over funding decisions. The other owners

[341] Barrett further testified that he did not participate in the preparation of the costs or savings estimates. He stated that he was handed cost estimates, savings estimates and a target completion date for the project. Tr. 5664:13-65:14.

[342] Carriers IB 148.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

knew this. Tr. 4731:7-11. Contrary to the Carriers arguments[343] BP blocked further study of the hybrid option.[344] Ex. SOA-472.

505. It is concluded that by the beginning of October 2002 if not earlier the Carriers had already predetermined the outcome, they had chosen electrification. This is another reason why the numbers for the staffing for hybrid or electrification from this point on are not credible.

506. The Carriers chose to ignore the concerns by some parties about the information and the economics of electrification and informally cut off any appropriations for further study of hybrid. As Staff points out, the selection of electrification over hybrid has been shown not to have been based on, and supported by, "a thorough consideration of alternatives. Further, Staff avers that the decision to proceed with electrification was not "consistent with sound project management practices," nor was it reasonably "compelled by the projected economics." Staff RB 15. For instance, they ignored M. Yaege's requests for further study of the hybrid option. Exs. SOA-182 at 2-4; SOA-472; SOA-185 at 4. Staff correctly points out that the Carriers chose to embark on SR against the advice of its own consultants and employees, the economic analysis counseled against electrification and there was no scrutiny or approval by state regulators. Unlike in *New England Power Co*., it is not difficult to imagine the many things the Carriers could have done to be more reasonable and prudent in their decision-making process.

5. What happened in 2003

The SR Project Management Team- January 30, 2003

507. The SR Project Management Team was formed by the Carriers to implement SR. Ex. ATC-166. The SR Project Manager (Barrett) reported directly to the CEO of Alyeska (Wight).[345] Tr. 5687:9-12. Ex. ATC-166 at 3. I. Livett, the Pump Station Electrification Project Mananger, was on loan from BP. Ex. ATC-166. The project manager for SCADA, Telecom & Control Systems Projects previously worked for another pipeline. Both managers reported to Barrett. Ex. ATC-165 at 14. These two

[343] Carriers IB 127.

[344] Due to its ownership share, BP effectively has veto power. Tr. 3156:24-3157:3; Tr. 3898-99; *see* also Ex. AT-243 at 4. The TAPS System Agreement provides that approval of projects requires: (i) agreement of BP and at least either Conoco or (ii) Exxon and at least either Unocal or Koch or (iii) the agreement of BP, Conoco or Exxon. Tr. 3094:10-20; *see also* Ex. AT-243 at 4; Ex. ATC-261 at 3.

[345] The CEO, David Wright was on loan from BP ("secondee"). *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

managers did not have previous Alyeska or TAPS experience.[346] The structure of the team was separate from Alyeska operations.[347] Ex. SOA-292 at 3.

Funding for Preliminary Engineering Studies

508. The authorization for expenditure for preliminary engineering for electrification is AFE SO20.[348] Ex. ATC-165. The January 16, 2003, funding request was for $7 million in capital spending. *Id.* at 3. The request included overall program management, engineering and operations studies, initial permitting activities, development of contracting and power source strategies for electrification of the pump stations and related control system upgrades. *Id.* at 5. The deliverables included preliminary engineering design for each pump station with specified major equipment and vendor quotations; updated costs estimates to +/-15% accuracy; draft of power contract(s) with cost and terms of service and economics for purchased vs. on-site power; permitting and regulatory issues identified and submittals prepared in draft form; maintenance plans; organizational charts for future operations, maintenance, engineering, business and support groups and a human resource plan for the transition to the new organization. *Id.* at 6.

509. The request states that the capital costs uncertainty associated with electrification is stated to be -15/+30% and preliminary engineering will reduce this to +/-15%. The Carriers assumed that Hybrid would have greater uncertainties due to the risks of modifying older equipment in the field. The requests states that up-front planning and good project controls are keys that will help keep the projects on track. *Id.* at 27. The document also states that the costs can escalate since accuracy is limited at the front-end of a project and costs can increase as scope is better defined. *Id.* "Sufficient engineering needs to be completed to minimize "scope creep", changes, and re-work." *Id.* at 28.

510. The pump stations within the scope of AFE S020 are PS-1, 3, 4, 5, 7, 9 and 12. The AFE recognizes that PS 7 and 12 are less important because the forecasted throughput levels do not support their long term use. *Id.* at 29. It is noted that the AFE was solely to study electrification.

Pipeline Planning Team- February 6, 2003

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[346] There were two other managers who directly reported to Barrett. Ex. ATC-24 at 7.

[347] Evidence in this record shows the Carriers wanted to promote "breakthrough thinking" with the structure of the SR team. Ex. SOA-292 at 3 and Ex. SOA-275 at 136:4.

[348] The State IB describes the AFEs approved to fund SR. State IB, App. at 288.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

511. A Pipeline Planning Team is formed to "facilitate decisions by the TAPS Owners and Alyeska with regard to pipeline issues. The lead planning representative at the time was M. Rocereta from BP. J. Ray was the Exxon representative and P. Flood for Conoco. This is to try to speak to "Alyeska with one owner voice" and address owner alignment issues. Ex. ATC-167.

Status Report

512. A February 20, 2003, Strategic Reconfiguration Status Report (Ex. SOA-197 at 7, note that the first 6 pages of the exhibit are dated December 2002, pages 7-11 of the exhibit are dated February 20, 2003, pages 12-15 are undated and the last page is dated May 7, 2003) states that the project management team has been hired. The document again notes that the cost estimates are "order of magnitude," contingencies were not included, project management and Alyeska costs were not included, and that the estimates are "adequate for comparison of alternatives, but not for project funding. *Id.* at 9. Concerning the schedule it notes that it is aggressive, with very little flexibility, with "zero float for three years," will require timely decisions and flawless execution. *Id.* Concerning project funding the document points out that the project schedule and budget timing are not aligned. The gate process and funding strategy will be included in the overall plan. *Id.* at 10. It notes that the project funding and contracting strategies have to be developed and that the Planning Team must be used to maintain Owner/Alyeska alignment. *Id.* at 11. An "economic analysis conclusions" is on page 9. The bullet points state as follows: Economics are positive for both hybrid and electrification (alternatives are not equal, NPV for electrification exceeds hybrid); Hybrid (+ requires less investment, + begins to save more money immediately, - lower probability for success, - lower overall savings); Electrification (+ greater long-term savings, + higher confidence level, - more up-front capital required); Electrification provides environmental advantages not available with Hybrid; Hybrid and electrification are not incremental (one alternative must be selected over the other.). *Id.* at 15.

EMPC Gate 2 Endorsement Review

513. In an independent evaluation to endorse (Gate 2), on or about February 20, 2003, Exxon states that the cost accuracy is limited, project front-end costs can increase as scope is better defined. Sufficient engineering needs to be completed to minimize "scope creep", changes, and re-work. Exxon also pointed out that costs of major equipment may change as a result of overall world economy. Ex. SOA-286 at 21. In this report there is zero contingency but included "$11 million for transmission line to PS09." *Id.* at 16. Identified as an issue is: control cost escalation (scope creep). *Id.* at 2. An operating risk is pointed out, several projects are being completed at the same time that must come together to make SR successful. Up-front planning and good project controls are key factors that will help keep these on track. *Id.* at 20.

Exxon Memo dated February 26, 2003

20140227-3052 FERC PDF (Unofficial) 02/27/2014

514. A memo from M. W. Massey (ExxonMobil Pipeline Co.) to T. R. Walters dated February 26, 2003 requests Exxon Mobil Production Company to take no exception to ExxonMobil Pipeline Company's approval of AFE S020. Ex. SOA-252. The memo states that "there is still work to be performed before we get fully comfortable with the cost estimates. . . no contingency was included for any of the alternatives. Handwritten notes on page 2 state: "We need to keep pressure on the other Owners to carefully evaluate/consider the benefits of the increment above "optimized." Internally we are moving to something in excess of [ ] percent RoR [Rate of Return] for capital projects that are primarily justified on expense savings." *Id.* at 2.

515. ExxonMobil explained its decision/gate review process and states that it would need Gate 3 approval and "the approval of additional advance commitment $s (to reach Gate 4) by November 1st. Per a discussion with J. Barrett, the anticipated need is $14M ($5M for procurement of long-lead items, $5M for detailed engineering, and $4M for the Project Team for $2004). . . Gate 4 and approval of full funding), would be required by the end of 1Q04." Ex. SOA-261. The time-line which provides one month for owner approval is deemed very tight for ExxonMobil. *Id.* The document describes the Gate 3 requirements "(i.e. what is typically required by management at this gate)": design basis/scope definition, project plan/schedule, Class III cost estimates (including contingency) +/- 15%, economics vs. alternatives (all cases on the same basis), Key issues identified/mitigation plan, HR plan, permitting plan, communications/public affairs plan (draft), Front End Loading assessment (industry consultant-IPA), cold eyes review/peer reviews, SHE assessment, advance commitment request (last number was $14M). Gate 4 requires: engineering and process design, Class II (+/- 10%) cost estimates (including contingency), project schedule, economics vs. alternatives (all cases on the same basis), permits (in hand), construction bids (in hand), hazard/operability assessment (HAZOP), FEL Assessment, cold eyes review/peer reviews, communications/public affairs plan (corporate approval), full funding request. *Id.* at 1-2. The document notes that ExxonMobil's main concern is that we evaluate all options on the same basis, all should be for 1.14MBD capacity, assume regional spill response and urban schedules where possible for Hybrid (either as a primary case or sensitivity). *Id.* at 2.

Emails February 27-28, 2003

516. J. DeHaaas, Alyeska's Rotating Equipment Engineer wrote an email dated February 27, 2003, disagreeing with the cost estimates for strategic reconfiguration. Ex. SOA-282. He assert,s he disagrees with the costs savings, the assumptions and figures. Further he states "What is even more odd is that very little if any of what I have seen is reviewed by a competent rotating equipment engineer, before it goes out. The primary component of this project is rotating equipment." *Id.*

517. In another email dated February 28, 2003, DeHaas states that the annual maintenance costs on the MLU packages should be in the order of $ 2 million dollars per year, for all the packages presently in service. Ex. SOA-473. In addition, he states that

20140227-3052 FERC PDF (Unofficial) 02/27/2014

close to 1.6 million per year is spent on Avon repairs, Cooper RT and mainline pump repairs are minimal, "very minimal." "We have had one pump seal changeout for maintenance reasons, in 3 years." *Id.* Looking into the future it would be expected that the costs will remain fairly steady. It is possible we could go lower than this. He further states there are no obsolescence issues regarding the mechanical equipment. All equipment can be operated and repaired for a long time into the future. "We have a very generous supply of RT turbine and to a lesser extent pump part, in inventory and in shutdown pump stations. We have several decommissioned Avons that can be parted out as well, for a potential reduction in overhaul costs." *Id.* DeHaas goes on to state that the annual maintenance for the Garrett and Solar packages is about $0.5 million dollars per year.[349] *Id.* at 2.

518. DeHaas statements are consistent with what was stated in the Electrification vs. Hybrid document that the equipment was operating extremely well, reliability was very high and unplanned shutdowns are rare. It included the statement that it was working so well maintenance personnel are not retaining their skills in tasks such as changing mainline pump seals, etc. Ex. ATC-154 at 31. Thus, Howitt's testimony contradicting these statements is found not to be credible.[350]

Email April 7, 2003

519. On April 7, 2003, they are still working on the schedules for the "Electrification vs. Hybrid Decision Summary." Ex. SOA-186 at 6. ExxonMobil states that all 3 alternatives (Inertia, Hybrid and Electrification) should be on the same basis/assumptions (i.e. only provide costs in the Inertia case to upgrade/replace facilities to yield 1.14MBD capacity vs. current 1.5MBD, align manpower assumptions for Hybrid/Electrification (regional spill response and daytime only work hours where applicable). There are obvious inconsistencies between the cases that management was able to identify. *Id.* at 4. The document also states: "I don't see why we wouldn't include additional costs savings (i.e. turbine maintenance in Inertia case) as well as any additional costs that will be incurred (i.e. potential additional switching costs) recently identified if our goal is to present the true facts to management for decision making purposes." *Id.* at 5. The email dated April 9 states, "[t]he conceptual case for a reconfiguration is so compelling that it has been adopted and approved as the official long-range plan of the company. With this kind of momentum, it does not seem prudent to perform preliminary engineering for the do nothing or Inertia Case. This effort will be strongly aligned with the reconfiguration

[349] This includes the generator, booster pump, injection pump and fuel gas compressor packages. *Id.* at 2

[350] Howitt testified the mainline units had a history of requiring frequent and immediate operator intervention to maintain safe and reliable operation. This operator intervention was required by such things as failure of a main pump seal. Ex. ATC-19 at 130:12-14

20140227-3052 FERC PDF (Unofficial) 02/27/2014

alternatives in terms of scope and timing." *Id.* at 1. Again, additional evidence that the Electrification vs. Hybrid document is not entitled to any weight, since the decision to electrify had already been made.

Email April 10, 2003

520. On April 10, 2003, ExxonMobil expressed concern about being able to obtain full funding approval for electrification "using the Alternative Plan."[351] Quantifying it as a high risk ExxonMobil would have difficulty obtaining full funding. This is discussed in an email from C. W. Hatley/Houston/ExxonMobil to P. Flood from Conoco. Ex. SOA-173. The document states:

> EM management would be very reluctant to provide full funding to such a large/complex project at what we would consider to be Gate 3
>
> It is likely that the Front End Loading Assessment would yield an unfavorable score, indicative of projects where risk is high that either schedule and/or budget goals will not be achieved
>
> IPA studies demonstrate that accelerating projects to meet earlier schedules so you can "start saving money soon" rarely pay out. Instead, what is typically seen is that project acceleration causes one to miss out on Value Improving Processes and you therefore are forced to live with a suboptimized project. Therefore there will be some who question the logic of project acceleration (both Conceptual and Alternative Plans) to achieve a 4Q2005 start-up

Ex. SOA-173.

SNC-Lavlin and Hinz Automation Awarded Contract

521. Canadian contractors SNC-Lavlin (Lavlin) and Hinz Automation (Hinz) were selected to perform the preliminary engineering for electrification. Ex. SOA-232 at 1.[352] Lavlin was lead for electrification. Contracted on April 28, 2003 work to start on April 29, 2003.

522. The selection of this contractor is questionable, they were ranked 2 out of six and the comments on the ranking sheet states "Proposed lead has no pipeline experience. Other team members are okay, but light on hours. Poor understanding of scope." Additionally in overall ranking it was number 2. It also received the lowest score on prior Alaska experience, artic conditions seismic understanding. Ex. SOA-217.

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[351] It is not clear from the record in this proceeding what this means.

[352] *See also* Ex. ATC-428.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

523. Hinz also had limited experience working in Alaska or on TAPS and was ranked 2 out of six. Hinz was selected to lead the automation portion. [353] *Id.* These contractors were not paired off with local contractors.

May 2003

524. In a May 7, 2003, document the status of Strategic Reconfiguration is discussed. Ex. SOA-232. At this point in time power options are being considered. *Id.* at 1. The SCADA host project has been delayed to coordinate with strategic reconfiguration (operating and control philosophies are being reconsidered). *Id.* at 2. Permitting requirements are being identified and are 90% complete. Concerning the schedule the document states the "schedule and options for funding continue to be a challenge." Schedule is tight, but 2005 start-up is possible. *Id.* at 3.

525. The schedule contemplated preliminary engineering starting in April and being finished by September 2003. Long-lead equipment overlaps with preliminary engineering from the middle of July through the middle of August 2003. Purchase orders overlap with RFP/Bid/Contract from September 2003 through December 2004 overlapping with detailed engineering. Detailed engineering starts in February 2004 and ends in August 2004. Remainder procurement overlaps with detailed engineering starting in the middle of March 2004 and ending in March 2005. Work on the site foundations starts in February 2005 and ends in March 2005. The module fabrication starts in October 2004 and ends in May 2005. Start up is October through November 2005. Ex. SOA-232 at 4.

526. Concerning the schedule this document states that it may be the most significant challenge in 2003. There is a zero contingency, since the time frame is compressed. There is no tolerance for delays. It states that there is a need to plan ahead for expedient, effective decisions. The pace of work (and the need for flawless execution) will increase. Additionally, it notes that the schedule compression is causing gate review activities to converge. Moreover, non-typical funding strategy is required to meet the 2005 start-up. However, extending the project schedule is not recommended. *Id.* at 7.

527. Of note are pages 9-10 of this exhibit. Page 9 is titled "Forecast Production with Future Discovery Sensitivity." This shows the barrels per day being over 1 million barrels starting in 2006 based on new production and undiscovered oil fields. It is interesting that the Carriers have never argued this is the basis for Strategic Reconfiguration. However, in May 2003 this was part of the items being considered. This seems to explain why the conceptual engineering studies were based on 1.14mm barrels per day.

[353] Barrett testified he did not initially agree with SNC's selection. Ex. ATC-24 at 14:6-11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

528. This schedule is very troubling due to the fact that only six months were established for preliminary engineering and detail engineering to be completed. Additionally, procurement functions overlap preliminary engineering and detailed engineering. It is found that a prudent person would have waited after detail engineering to order equipment. The Carriers knew that they had compressed the time frame for both preliminary engineering and detail engineering. Thus they assumed the risk that their estimates were wrong (which ultimately happened) in terms of costs, regulatory assumptions, scope of the project. The Carriers also knew that Bailey had estimated 5 years to finish the automation project, which rendered their new schedule in the realm of unreasonable.

Email from Ahrens to Barrett May 27, 2003

529. The subject line of this email states "Philosophical Budget Question." Ex. SOA-561. "I'm going to suggest a going-in position that will cause us to defend our position at every turn. It is based on the proposition that we're no longer selling the project, but executing the project." *Id.* The document states that the decision document capital number for electrification of $120 was based on a cost reduction proposal by GE (9/19/02) for one big turbine at each site, combined with up rated emergency generators. It then describes the spread between the estimates done by GE and those done by JTG. It concludes by stating that "[s]ince we don't have any new numbers to replace the conceptual, and in order to be consistent with the budget and AFE philosophy, I suggest we add at least 30% to Electrification and Control Systems upgrade numbers." *Id.*

Email J. DeHaas June 9, 2003

530. In this email DeHaas discusses the 10 yr. Maintenance Plan. Ex. SOA-497. He states that I'am a bit leery of the accuracy for a plan that is 10 years into the future, especially based on our major maintenance history/performance. He continues with a recommendation to Vance. To wit: "Vance I recommend you be conservative here and do some sensitivity analysis to get a feel for how much room we have for error; as you know, it would not be good to overstate the case for proceeding with SR. We will live with this for a long time." He further states: "If I am asked what the turbine budget will be for 2005 and beyond, if SR does not proceed, what do I give for an answer? The actual which will be much higher than normal due to the fact we booked some savings in prior years, which did not really occur. Or do I give the average actual that would have occurred if SR had not been considered." "It appears to me that the door is being left wide open here, for use of some economic justification that is really false." *Id.*

Email July 24, 2003

531. G. Jones[354] writes an email in July 24, 2003, to J. Johnson and P. Flood (Conoco) expressing concerns with the SR timeline. He writes: "It has felt like we have been

[354] The State's IB identifies Jones as Alyeska Senior Vice President, Operations & Maintenance.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

reacting repeatedly to the "thinking out loud" of some members of the S.R./planning team. Although well intentioned, the ideas were not always vetted with the right teams before setting them in motion. It also makes it difficult from a project management standpoint as the scope is forever changing." Ex. SOA-453 at 1-2.

Emails J. DeHaas July 26, 2003

532. J. DeHaas also expressed concern with the design the SR project during this time frame. As a matter of fact, he wrote in an email that he did not agree with the electrification design basis. "In fact I think portions of it quite absurd, to put it in plain language." Ex. SOA-187. Of significance, he further states: "I think it good to understand that Ian (as I understand it) was more or less given a mission that required use of the electrification approach. *Id.*

533. In another email on the same day DeHaas wrote he was in favor of turbine driven pumps at each pump station, especially at PS3/4. Ex. SOA-560. Concerning the environment he states that it is directly related to the amount of equipment purchased, amount of field construction and footprint. He states that "it appears the amount of equipment that would need to be purchased is significantly less via the turbine driven pump route." *Id.* He adds that another aspect of environmental is emissions and process efficiencies or overall pumping efficiency. He states, "the pumping efficiencies will be much better at PS03/04 if the turbines are direct or gearbox driven to the pumps. This is also true at PS01 . . . At PS03/04 we are probably talking about overall pumping efficiencies on the order 28% for the turbine pump scheme, versus 24.5% for the electrification scheme." He comments that: "It would seem completely inappropriate in my opinion for Alyeska to even consider a less optimum approach, from an environmental perspective, in particular if the cost was the same or less for the better environmental approach." *Id.*

534. In terms of reliability DeHaas states that "reliability goes down with installation of more components, as appears to be the case with the current scheme at PS03/04, compared to the turbine driven pump scheme." Further, he states that "some folks give the impression the turbine driven pumps and/or remote operated turbine driven pumps are something seldom used, complicated and unreliable. This is totally untrue." *Id.* He gives two examples from his experience going back 20 years. *Id.*

August 2003

535. In an e-mail dated August 25, 2003, V. Schwantes states that they were anticipating actual lifecycle replacement costs on the equipment to be lower and thus the control system related savings will not be as large as previously indicated. Additionally, he states that the economic model is not compelling but the results are positive using extremely conservative preliminary information. Ex. SOA-454 at 2. Barrett replies shortening to September 15 (from September 30) the data gathering effort. Schwantes responds on August 26 stating that the September 15 target is challenging. *Id.* He states

20140227-3052 FERC PDF (Unofficial) 02/27/2014

that he is concerned about "cost forecast quality at 9/30. According to Schwantes there are major gaps in staffing levels and maintenance forecast.

536. Additionally, he conveys that:

> We "discovered" last week that the conceptual economics included $55M of control system automation in the Inertia case. This is obviously inconsistent with our understanding of the Inertia case, but according to Cliff (yesterday), "the Inertia case assumed unmanned stations." I haven't fully explored that statement."
>
> Unless I'm way off base, this means a significant reduction in costs of the Inertia case, and therefore a reduction in the major maintenance savings.
>
> Per review by Cliff and Steve Schudel, it appears most of the control system savings are already captured in the $88M of major maintenance savings we've identified, which is a significant reduction in savings from the $152M stated in the conceptual economics.
>
> In addition, I feel the quality of the major maintenance forecast is still a bit weak.

Id. at 1-2.

Email J. DeHaas September 18, 2003

537. In an email dated September 18, 2003, J. DeHaas also states that the Inertia case is higher than he had originally estimated. Ex. SOA-488. He states he added all the columns for Inertia and the result is $38.8 million, higher than what he had originally estimated. He states he has not been involved in the study since the first two pump station runs. Further he asserts that considerable money was thrown in for upgrades so the $38.8 is twice what he had estimated. Moreover, he states he does not believe that the additional upgrades are necessary for the legacy equipment. However, he does believe that some upgrades and rework will have to be performed to the new equipment as well. He points out that at the current flow levels "Avon turbine hours" will continue to decline, over the 10 year period and this has not been factored in. *Id.* He concludes by stating that "In summary it is my impression that these cost estimates regarding the turbine equipment are incorrect." *Id.* [355]

538. As a result, it is found that they were working the numbers in a hurried manner without sufficient time to give adequate study to the numbers. Therefore, these numbers

[355] Notice that an email dated September 16, 2003, from S. Walley-Hoff states that the workbook is a detailed accounting of every equipment system (including sub-systems) at pump stations 1, 3, 4, 5, 7, and 9 and is 85% complete. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

are not given significant weight, and it is found that the Owners knew that the numbers were rough order of magnitude. Moreover, the emails from DeHaas above, seem to infer that the numbers are contrived.

Comparison Between Direct Turbine and Electric Motor Driven Pumps

539. This study concluded in September 2003, assumes grid power at PS1 and PS9 with back-up generation and 6.5c per kw-h for power at PS9 (GVEA budget price), $1 per gallon for diesel, $2.0 per mscf for natural gas and 0.5c per kw-h plus value of gas burned for power at PS1. Ex. SOA-165 at 4. In the conclusions this study states:

> Direct turbine drives is a viable alternative for the reconfigured pump stations and the case with 2, 2, 2, 2 turbine driven pumps at stations 1, 3, 4 and 9 offers the lowest capital cost solution
>
> The best option considering pipeline availability, capital cost, lifecycle cost, scalability and schedule (project and benefits) is the current electrification base case (3, 3, 3, 4 electric motor driven pump stations at 1, 3, 4, and 9).
>
> A hybrid option considering a mix of electrification and direct drives could reduce capital cost further but requires further study prior to sanction to fully evaluate the impact on O&M savings, training, OCC operations, support organizations, inventory and sparing, and project economics.
>
> Change of concept at this time will delay the current 2005 completion schedule.

Id. at 16.

In terms of what the owners knew at this time this is significant because they were being told there were lower capital cost solutions.

October 1, 2003

540. J. DeHaas by email dated October 1, 2003, opines concerning the above study (SR Mechanical Drive Study). He starts by stating that the numbers presented are incorrect or that he does not trust the numbers. Ex. SOA-284. He questions what supported the underlying numbers. *Id.* at 2. He further states that all maintenance costs are incorrect. Further, he says that the study was biased. "If it was good and technically accurate one would not read inaccurate comments that indicate electrical drive turbines have better maintenance and reliability than mechanical drive turbines. It is biased because SNC does not want to do a mechanical drive option. SNC Lavlin wants to milk this job, . . ." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

541. Additionally, DeHaas states that SNC knows very little about maintaining and operating turbines or rotation equipment. Moreover, he adds that he has not been consulted and his opinions have not been accepted. DeHaas opines that the study confirmed a very good hybrid possibility, which is to install mechanical drives "up north, and electrical drives down south. According to him, this would save considerable money. Further, he asserts that the electrification option is the least standard of any of the concepts. "It requires a mix of equipment and concept at two pump stations, which is more non standard than any other concept, including a hybrid concept." *Id.*

542. On October 1, 2003, there is an email from T. Smart to P. Spaans and others, concerning the scope of work for the hybrid case. Ex. SOA-723. The attached document states the scope for the hybrid case to be accurate to plus or minus thirty percent. It notes that the execution strategy, schedule, and risk for the Hybrid case are different than the full Reconfiguration case and that these factors significantly affect the amount and accuracy of the cost estimate. *Id.* at 3.

Emails October 3 and 7, 2003

543. I. Livett by email dated October 3, 2003, summarizes the conclusions of the study comparing direct drives pumps and electric motor driven pumps. Ex. SOA-452. He states that it is generally (not unanimously) agreed, and supported by the owner representatives, that the study results did not provide a compelling reason to change the current project direction at this time. The potential capital savings from the alternative options are offset by the impact of project delays and questions relating to scalability, availability and overall O&M savings. *Id.*

544. E. L. Monthei[356] wrote an email on October 3, 2003. Ex. SOA-284. In the email he states that four of the "most knowledgeable Engineers are not convinced this makes good economic sense and I agree with their concerns. The configuration will costs $12-million more, will be less reliable, and be more costly to maintain. Of more concern to me is that the Engineers feel their concerns were not considered and that they were shut down by Kevin Brown and Joe Riordan who spoke with passion but not with sound engineering justification." *Id.*

545. Another example of concern about the SR project is an email from G. Jones, Senior Vice President, Operations and Maintenance for Alyeska dated October 7, 2003. In this e-mail Jones analogizes the SR project to other problematic projects, the OSCP and the PS12PLQ, which he states, suffered from strikingly similar problems. Ex. SOA-280. He states (agreeing with DeHaas and Monthei) that the engineering team is disconnected from the project team, they were forgotten initially, and when they were brought in, they feel that their opinions are not being considered. In addition, he states

[356] Monthei at the time was Alyeska's Vice President Engineering and Projects. He later replaced Barrett as SR Program Manager in 2005.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

that the engineers believe there are errors in the analyses, including present value numbers, "but no one on the project team apparently wants to listen, or we can't change course now because it is too late. They are frustrated and find it incredible that "hired vendors" are apparently in such complete control. They are frustrated because they have had no real influence on the proceedings, and there is no time for peer reviewing of work and/or carefully checking things along the way. Jones points out that these are quality people saying this and further that "the noise is really in lots of places not just engineering." *Id.*

546. He states from my vantage point after a review of the 3 cases (Eng, OSCP, PS12) the common breakdowns are as follows:

1. The company experts or clients are not consulted with early on, or if they are, their input is dismissed because it does not conform to preconceived views about the answers, including costs.

2. Cost and schedule pressures to make the project "a go" are permeating interactions with client teams, giving the appearance that the project team is the decision maker, and turning folks off.

3. Owners staff are more connected than the client teams and perceived as part of the culture problem.

4. Project team resources do not appear to match the current workload, impacting very heavily some client resources.

Id.

547. He goes on to state:

> that we are disfranchising the people we need engaged to pull this off. I must admit when you step back and think about how much planning went into construction (years of it!), this whole thing feels rushed, which is perhaps one of the biggest factors getting in the way of careful and deliberate coordination, as well as MOC (which is still behind the power curve too!). …but left on our current course, my concern is we are going to find ourselves doing the "insanity" thing if we are not careful; that is, repeating the same thing over and over again but expecting a different result.

Id.

548. Additionally, Jones asserts that Barrett and Howitt are not seeing what is happening and states "if they don't get it, we are going to keep repeating history." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

549. Accordingly, it is found, the Owners knew that quality employees were questioning SR, the costs and the savings.

October 23, 2003 (Transition Engineering/AFE S020 & S024)

550. On October 23, 2003, Alyeska requests an additional $3.5 million capital for the next phase of SR. They call this "Transition Engineering" to extend the work occurring simultaneously under two approved AFE's S020 (Electrification) and S024 (Station Controls Upgrades). Ex. SOA-62. It describes the activities as program management ($1.2M), transition engineering ($1M), long-lead materials procurement (engineered drawings, $1 M), and some contingency for term staffing contracts ($0.3M). *Id.* The engineering activities to be executed under the request include design for the Command Modules to be installed at the ramp down stations in 2004, finalize retained building study and site layouts, Station Control Philosophy document, identification of pile locations critical to early construction, and engineering support in preparation for procurement for modules and other station control equipment. *Id.* at 9.

551. The AFE S024 submitted April 9 is found on page 11. It states that the AFE Phase I is for preliminary engineering for pump station control system upgrades. *Id.* at 11-12. At page 14, the scope includes detailed cost estimates for all major equipment and detailed strategy for integrating with the SCADA and telecommunications systems. The scope also includes a resource loaded schedule for detailed design and implementation phases. *Id.* at 14.

552. Page 15 of this document states that "a significant part of the savings proposed by the SR project will come from automation of the pump stations (allowing for reductions in staffing levels). Another significant savings opportunity is in electrification of the stations and avoidance of planned major maintenance activities.

Further Concerns – Emails October 24 and 26, 2003

553. On October 24, 2003, H. Weyerman,[357] expressed concern over a significant number of things in SR. For instance, he states that the "Design basis is sound but not optimal in our opinion, and schedule and execution seem to be very aggressive (added risk to meet scheduled start-up)." Ex. SOA-260. He goes on with more specificity, to wit:

1. Projected maintenance savings might be over-aggressive considering cultural change to regional centers, dependence on sophisticated remote communication and diagnostics.

[357] The State in its IB states that Weyermann is a TAPS Owner representative for Cononco. IB 78.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

2. Economics did not reflect costing for next generation of electronics (VFD, SCADA); electronics will become obsolete again within the 20-year life, while mechanical equipment will be ok.

3. The wisdom of electrifying PS3/4 was not fully explained. We question whether turbo-generator/electric pump is more reliable than direct drive turbo-pump. Also large transient conditions (e.g. loss of 50% power in case of genset trip) are of concern. What are the dynamics in the VFD's and motors in such incident, w/o shedding load?...

4. We have concerns about the potential lack of integration between Alyeska SCADA upgrade and the Reconfiguration project- does it consider bandwith, … Aggressive schedule means that a lot of detail must be executed correctly in a short time. Failure could jeopardize whole remote operations concept.

5. . . .

6. Not obvious that contract strategy and projected execution plan promotes alignment/integration for a schedule driven project. What is the critical path? Is there a float or a contingency plan?

7. Is Alyeska considering outsourcing of power generation?

Id.

554. D. Ahrens,[358] on October 26, 2003, by email to I. Livett and P. O'Farrell, increases the cost estimates for the 10/28 peer review presentation. He states: "The fact is that the Hinz estimate for the equivalent scope has increased from $37M (10/9) to $49M (10/20) to $57M (10/24), and I think we need to address the increase now, as opposed to waiting until we submit the sanction AFE. Thus, it can be gathered that the Hinz estimates increased by more than 50% in fifteen days.

Final Program Execution Funding Review Meeting

555. A meeting between the TAPS Owner representatives, Owner staff, Alyeska and contractor representatives was held October 28-29, 2003. The intention of the review was to determine the readiness of the program to move from FEL 2 (Development Planning phase funded by an AFD) to the FEL 3 Execution Phase. In other words to

[358] The State IB describes him as the SR Project Control Manager. State IB 79.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

determine readiness of the Owners to fund the project. Ex. SOA-475. Noted was the fact that there were significant and notable deficiencies in several areas: "development and documentation of risks and opportunities in the estimates and forecasts, particularly in the operating and maintenance savings element of the project justification but to a lesser degree in the project cost; documentation of some significant program execution plan components; development and documentation of overall program change management and development and/or documentation some operation/maintenance planning." *Id.*

556. The document states in terms of the probability based estimates and forecasts that they were, "based on strictly deterministic basis for investment (with some discussion of project risk analysis but no documentation)… While assurances were given on the conservative nature of the absolute investment (P80?), and the targeted savings (P75-P95??), no evidence was provided." *Id.* at 3. In terms of cost savings sensitivities to project scope and timing the document notes that the work to review individual pump stations had not been completed and it was agreed to modify the base electrification case and run two scope reduction cases. *Id.* It was also requested that timing sensitivities include delay of one-to two years. *Id.* at 4. Likewise, the costs studies have to be developed further with a contingency study. *Id.*

557. There is an interesting entry in this document. It states "Revise/update the next best alternative for economic analysis-Combine the existing "inertia" and "hybrid" cases into a single "what would we really do if we don't electrify" case, and verify that this consolidated case incorporates all the learnings/contingencies identified (and accounted for in the Electrification case) … This will ensure that the economic comparison between cases are valid." *Id.* The record in this case does not show a comparison between electrification and "what would we really do if we don't electrify case." Moreover, it seems an invalid comparison to jumble together inertia and hybrid.

558. Concerning schedule management the document states that the "schedule was characterized as tight and we agree." *Id.* Additionally concerning change management the document states: "A change management plan for all elements of the program must be developed and documented. The plan should address **lockdown of project scope**, authorizations and responsibilities for change management, including requirement for TAPS Owners scope change/cost change authorization. *Id.* (emphasis in original).

559. The document also states that some of the changes for instance to PS 5 are justified as replacement of facilities for execution savings/efficiency reasons. It states that the study should include PS 5 in both inertia and electrification. *Id.* at 5. It is noted that the savings from changes to PS 5 are not included in hybrid. The document also makes recommendations concerning the number of spare equipment at the pump stations. *Id.* at 6. Concerning the automation plan it is stated that there is a gap in development of automation scope and execution plan. "Integration of asset management (maintenance and reliability functions) and pipeline operations (SCADA) into a coordinated network is based on a vision, not an established plan." *Id.* at 8.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

560. Further, concerning maintenance, the document states that the plan is to have regional maintenance centers with planning and response directed from the OCC (or some other centralized monitoring function). "The functions and scope of how this will be accomplished are not well developed thus the Automation architecture cannot be validated. Several possibilities could result from proceeding without a robust plan for this element of the Pipeline Strategic Reconfiguration program: OCC systems and operators are overwhelmed with alarms and advisory information related to maintenance." *Id.*at 8. This was prescient, this is what actually happened.

Email from G.R. Shotts November 3, 2003

561. In an email dated November 3, 2003, G. R. Shotts,[359] explains Unidentified Major Maintenance. This category is to account for those projects that "we currently have no visibility over . . . unanticipated projects that seem to crop up every few years. The dollar amount in this line is a percentage of identified major maintenance, using the following schedule: "0 in 2004, 20% in 2005, 40% in 2006, 60% in 2007, 80% in 2008 and 100% in 2009. Ex. SOA-141. Note that the email states that "our ability to accurately project major maintenance costs decreases in the out years." *Id.*

Preliminary Engineering (Nov 3, 2003)

562. Exhibits ATC-208-216 are the preliminary engineering report for Pump Station Electrification and Control System Automation dated November 3, 2003, prepared by SNC, Hinz and JTG. The Executive Summary states that the Right Of Way (ROW) contract was renewed in January 2003. Ex. ATC-208 at 5. The document states that preliminary engineering was based on earlier conceptual engineering work and addressed electrification of PS 1, 3, 4, and 9, automation of ramp down stations (PS 2, 6, 8, 10, 11 and 12), automation of PS 7 and automation and additional re-injection pumping at the pressure relief facility, PS 5. *Id.* The design was based on a nominal throughput of 1.00mm barrels per day (MMBPD) of crude oil, a maximum throughput of 1.14 MMBPD and a minimum contingency flow of 0.3 MMBPD while achieving an availability of 99%. *Id.*[360] The new electrified stations and the ramp down stations are equipped with controls to allow unmanned operation and control form the OCC. *Id.*

563. Each station pumps are in a parallel configuration, with three units at PS 1, 3, and 4 and four units at PS9. Each pump and motor unit is controlled through a VFD. The new units at each station (pump, motor and VFD) are identically sized for common

[359] The State IB describes the title for Shotts as Alyeska Operations and Maintenance Supervisor. State IB 88.

[360] Note the document states that the new stations will be designed with no significant impediments to increasing the physical maximum flow rate to 1.5MMBPD. *Id.* at 13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

design and to minimize capital spare requirements. *Id.* The document states that a new power supply will be provided to PS1 and 9, from external utilities. "New power at PS 3 and 4 will be generated onsite by gas turbine generators. The station facilities are a modular design. The pump and motor units, electrical equipment, gas turbine generators and interconnecting piping and cables are all modularized. *Id.* Power and controls for remaining existing facilities (at electrified sites and ramp down sites) are rerouted to a new load center and new communications module. The communication module connects to existing facilities by load centers which contain control equipment, motor controls and power distribution equipment. *Id.*

564. The document states that an optional case (Hybrid) was studied but only at a conceptual level. *Id.* at 6. The project schedule requires the electrification stations in service by the end of 2005. Consequently, mechanical tie-ins have been planned during 2004 shutdowns and the control system automation will use the planned shutdowns in 2004 to complete the majority of the ramp-down stations. The balance of the automation work will be completed in 2005 in conjunction with electrification. This requires proceeding with commitments for major equipment vendor engineering by December 1, 2003, and release of fabrication of major equipment by March 1, 2004. *Id.*

565. The report states that the ultimate mission of the project is to minimize the cost of transportation of oil to extend the economic life of the pipeline and the North Slope fields. *Id.*at 7. The project "focuses on improving the four operating stations (1, 3, 4 and 9) and upgrading the monitoring and control systems elsewhere on the pipeline. *Id.* The goal of the Preliminary Engineering phase was to further study and verify the electrification case and do sufficient engineering to provide a high degree of confidence that the project is viable. "Sufficient engineering was completed to enable preparation of a +/- 15% estimate, Level II schedule and a detailed Project Execution Plan." *Id.* at 8. Additionally, the document sets forth that as a result of unmanning the pump stations, many of the existing buildings will be decommissioned or allowed to go cold. *Id.* at 9. This will permit the decommissioning of existing heating and refrigeration facilities and their replacement by significantly smaller sized facilities. *Id.*

566. The automation component provides automation of the stations in concert with an upgraded SCADA system. This requires reconnection of all facilities that would remain on the sites in the following groups: electrification sites (1, 3, 4, and 9); ramp down sites where no pumping facilities are required (2, 6, 8, 10, 11, and 12); PS 5, the pressure relief site, where the existing facility functions will be upgraded for unmanned operation and PS 7, where minimal changes will be made.[361] *Id.* at 10. Services required for the retained buildings at the electrification sites include heating systems, refrigeration systems, scraper launchers/receiver traps and relief systems. *Id.* at 10.

[361] This conflicts with the hybrid configuration case study which used PS 7 as the base case for hybrid. *See* Ex. SOA-163, *infra* at 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

567. Maintenance and response bases are planned for outside the perimeters of PS 1, 4, 5, at Fairbanks, Glennallen, and Valdez. *Id.* at 18. No security personnel will be at unattended stations. *Id.* Security systems for the operating facilities and the Maintenance and Response Bases at PS 1, 4 and 5 will be separate. *Id.*

568. Concerning the direct drive study this document states that case 5 which entails electrification per case 1 at PS 1 and 9 and direct drive per case 3 at 3 and 4 has the lowest directional capital costs and approximately saves $12.5 MM initial capital costs. Case 5 has the lowest total discounted lifecycle cost, approximately $19.5 MM (2005 US$) less than the base case excluding apportionment. When apportionment is included then case 1 (base case)[362] has the lowest total discounted lifecycle costs. *Id.* at 79. Apportionment is the result of deferred production which results in oil production being cut back, lowering the revenue of the producers.[363] Ex. ATC-212 at 24. The study assumed electricity, gas and diesel fuel costs. Ex. ATC-212 at 23. The recommendation is that the base case be pursued since "its lifecycle costs including apportionment are lowest, and excluding apportionment are not excessive. Other cases could be entertained to reduce initial capital costs if required." Ex. ATC-212 at 25.

569. It is concluded that the Owners included affiliate producer conditions to make a determination in favor of electrifying the pump stations. This is squarely in contrast to their arguments that they are independent entities. Moreover, it begs the question if they are independent entities, the affiliate producers should not have been considered when making such an important decision for the pipeline. The inclusion of producer considerations tilted the scale in favor of electrification which was definitely not the most economical in terms of initial capital costs.

570. There is an email dated September 5, 2003, in the preliminary engineering study, from P. Smith to I. Livett concerning the cost of natural gas and electricity for the direct drive study. To wit, P. Smith states: "by the way, the $1.09/MSCF … for natural gas is very low - equates to about $0.0039/kWh. I have been given $0.08/kWh to use for power from the utilities at PS1 and PS9. This makes the energy costs very low for natural gas compared to purchasing electrical power – for example [a]bout $0.5 MM for gas per year at PS1 compared to $9.8 MM for purchased [e]lectrical power. This would be a big driver towards the direct drive option being more economical than electrification." Ex. ATC-212 at 104.

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[362] Case 1- Electrification with 3 pumping units at PS1, 3, and 4, and 4 pumping units at PS 9 (3, 3, 3, 4). PS1 and 9 are tied to an electrical grid, and PS 3 and 4 generate their own power from 2 - 50% gas turbine generators. Electric motors and (Ex. ATC-212 at 23) Variable Frequency Drives (VFD's) are used. Ex. ATC-208 at 79.

[363] The study assumed the apportioned product has a value of $5US per barrel. Ex. ATC-212 at 24.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

571. It is also salient that one of the reasons listed in this document for going with electric drives to reduce operating costs, is that PS 1 and 9 "will likely operate on commercial power. Electric powered pumps at PS 3 & 4 will permit uniformity of design, operation, maintenance and spare parts." Ex. ATC-212 at 106. Additionally, it states that turbine driven electric generators (and control systems) are "off the shelf" designs. In addition, there is a reference to the fact that "gas turbine gen sets are optimized at synchronous speed. They operate more efficiently and produce less emissions at partial load. The capital and operating costs (per kilowatt hour capacity) for gas turbine generators decrease as the units get larger. Multiple small units will cost more than large ones." *Id.* at 106. At page 113 of this exhibit there is an email that states that the maintenance costs should be quite a bit less for the mechanical drive option. *Id.* The commercial power source at PS 9 is being discussed an unknown to J. DeHaas in this email. However he states that it is important to get fuel costs correct, "whether we pay them directly or indirectly," since they are "a significant driver." *Id.* at 114. The value of gas is cited as $2.0/MSCF and electricity is 2 cents per KW-H plus the value of gas if purchased from a third party at PS1. For PS 9 "use a diesel fuel cost of $1.0/gallon" and "average cost of electricity as 6.5 cents per KW-H." At PS3 and 4, assume value of gas as $2.0/MSCF for both turbine generated electricity and direct drive turbine fuel." (email dated September 8, 2003) from I. Livett).[364] Ex. ATC-212 at 104.

572. Additional things that needed to be determined according to the preliminary engineering report were: a detailed Safety Integrity Level (SIL) study following completion of a detailed HAZOP to determine if any additional control devices are required (Ex. ATC-208 at 10 and 75); the location of the OCC and an alternate (disaster recovery) control center location. *Id.* at 18. The pipeline controls was a high level overview. A complete document will be prepared during detailed design. *Id.* at 20. The resizing of the recirculation piping and valve would be performed during detailed design. *Id.* at 71. Any reconfiguration of the existing telecommunications is part of the SCADA Host project. *Id.* at 74. Evaluation and selection of sites to add pressure and temperature measurements at some of the Remote Gate Valves along the pipeline will be done as part of the detailed design phase. *Id.* at 76.

Project Execution Plan

573. SNC and Hinz prepared a project execution plan dated November 3, 2003. Ex. ATC-206. The stated purpose is to define the overall strategy, which is adopted by the selected EPCM Contractor for the execution of the SR project and to communicate this strategy to Alyeska and to other stakeholders. The expectation is that the selected contractor will develop specific execution plans appropriate to its procedures and specific

[364] The assumed costs for electricity are different on page 24 of Ex. ATC-212. For instance, electricity costs at PS1 is $3mm initial capital, gas cost plus $0.005/kwh, at PS 9 electricity cost is $0.065/kwh.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

organization. *Id.* at 3. It describes electrification as retirement of the existing turbine driven pumps and replacing them with electric motor driven pumps supplied by either external utility power or by on-site generated power. PS 1 and 9 are to receive power from the grid and on-site gas turbine generators will supply power at PS 3 and 4. Two distinct scopes of the work are identified (1) electrification of PS 1, 3, 4 and 9 and (2) pump station automation/retrofit of existing facilities. *Id.* at 4.

574. Electrification includes: unmanned remotely controlled operation; a common pump and motor size at each pump station arranged in a 3, 3, 3, 4 pump unit parallel configuration at PSs 1, 3, 4 and 9; the units are to provide the capability of increasing or downsizing capacity in the range of 1.5 to 0.3 MMBPd by the addition or removal of pump units; variable frequency drives control of pumps and motors; modular design. Unmanning the pumps will allow existing buildings to be decommissioned or allowed to go cold which will allow decommissioning of existing heating and refrigeration facilities and their replacement by significantly smaller sized facilities. *Id.* at 5.

575. The automation component provides for the overall automation of the stations in concert with the upgraded SCADA system and will require reconnection of all facilities that would remain on the sites after completion of electrification. The typical groups of sites are the following: electrification sites; ramp down sites where no pumping facilities or relief facilities are required PS 2, 6, 8, 10, 11 and 12; the pressure relief site where the existing facility functions are upgraded to unmanned operation. The automation and refit scope includes: site communications module; load center modules; motor control centers and low voltage switchgear, transformers; power distribution; PLC cabinets; fire and gas detection; 480 volt generators; critical power (UPS); PS 5 automation; site security equipment. *Id.* at 5-6.

November 5, 2003 Hybrid Configuration Case Study

576. Hinz produced a report by November 5, 2003, concerning the Hybrid Case. This case used the "renewal of PS7" as the basis of the study "because investment at the site itself was an option." Ex. SOA-163 at 3. According to this study the primary issue in the Hybrid case is the reuse and upgrade of the existing turbine driven pumping units. It goes on to note that the "existing Rolls Royce jets have served TAPS operation well and have been well maintained. The existing facilities have been well maintained and the buildings are still sturdy." *Id.* at 8. In the case of PS1, PS3 and PS 4 there is a natural gas pipeline to supply the station thus providing an economical fuel supply." *Id.* at 3.

577. The study notes that since October 2002, there have been changes resulting from preliminary engineering. "One item of note is the difference in the notion of what effort is required to implement the Hybrid case. 'The Hybrid option is considerably more complex than the Electrified installation. Essentially all of the facilities will remain in-place at each pump station. The Electrified option is quite different and removes most of the existing infrastructure.'" Further, it states that through preliminary engineering they have discovered an increased requirement for retained buildings. However, both cases

20140227-3052 FERC PDF (Unofficial) 02/27/2014

are complex in this regard since both contemplate rewiring the retained buildings to the Load Centers. Hybrid includes the additional complexity of doing major work in the operating Main Line Pump building. In the Electrification case, work on the new facilities is mostly performed outside of the operating area with the exception of the tie-ins. *Id.* at 8.

578. The study states that the Hybrid Case is based on the Full Reconfiguration case. "The major difference is the automation of the existing turbine pumping units in PS 1, 3, 4, and 9 rather than replacement with new drive units and pumps as in the Full Reconfiguration case. Thus, an additional Load Center and the retention of the Main Line Pump building" are required at each site. There are additional buildings to be retained at the sites as in the Electrification Case, and associated utilities and building services such as power generation, refrigeration, heating, etc. All other sites, including ramp down sites, have the same scope of work in both Hybrid and Full Reconfiguration cases. *Id.* at 4.

579. In terms of accuracy the study is supposed to be plus or minus thirty percent. It goes on to state that the execution strategy, schedule, and risk for the Hybrid case are different than the Full Reconfiguration and that these factors significantly affect the amount and accuracy of the cost estimate. According to this study, the implementation schedule for Hybrid is estimated to be twelve to eighteen months longer than the Full Reconfiguration schedule. *Id.* at 4.

580. Of interest is the fact that both Hybrid and Electrification require the retention of many of the existing systems. *Id.* at 6. It states "[b]ecause of the interdependencies of the systems in the buildings the determination of which buildings would remain didn't occur until later in the preliminary engineering effort." *Id.* The determination is set out in the Building Services Study by SNC.

581. GE gave an estimate of $540,000 per unit to upgrade the turbine for remote operation and a general upgrade of controls. However, the study increased this amount to $1,000,000 due to allowances for re-instrumentation and operations coordination. *Id.* at 7. Due to the fact that the Load Centers and Command Modules are the same for either option, costs for electrical, instrumentation and control work was derived from the Electrification estimates. *Id.* It includes the statement that to maintain alignment with Electrification the estimate reflects electrifying PS 5 and PS 1 booster pump rather than upgrading the turbine controls.

582. The first issue with this study is that it uses as a base case a PS which was subsequently not operational. Why would you study PS 7 which is not an operating station? As the study indicates "Depending on the rates from the shippers, pump operation at PS 7 may be required and in many cases could be offset by the use of DRA (Drag Reducing Agent). "In the outlook of the life of PS 7 with likely TAPS rate decline, the need for pumping there would go away. Then PS 7 would be treated as another Ramp Down site and retired." *Id.* at 3. Of note is the fact that the study itself recognizes the fact

20140227-3052 FERC PDF (Unofficial) 02/27/2014

that "[b]ecause of the decline in flow from the design capacity of the pipeline and the vintage of the turbines and pumps there is likely the opportunity for improvement in operating efficiency and emissions. *These were not evaluated as part of this study." (Emphasis added).* It seems unreasonable and unsupported on the face of the document the doubling of the GE quote for turbine upgrade for remote operation. The assumptions for PS 5 and PS 1 concerning electrifying pumps, does not seem validated. Further, it seems unreasonable to compare hybrid at conceptual with electrification at preliminary. It is comparing apples to oranges and one can only infer that it is the type of document made in contemplation of litigation.

Email dated November 6, 2003

583. JD Norton writes an email dated November 6, 2003, concerning job reductions from SR. He gives a total for Alyeska of 223 and contractors 149 or 372. However, he states "Note that approximately a third of these jobs will be eliminated anyway if SR does not proceed, due to other efficiencies." Ex. SOA-170. Discounting by a third would bring the total to 249.

Major Maintenance Savings

584. An exhibit shows identified major maintenance savings projected for the Hybrid and electrification options. Ex. ATC-245 at tab "Electrification & Hybrid totals."[365] The analysis compared Hybrid and Electrification to the Inertia option. The study was done for a 10 year period and doubled to determine 20 year savings. Tr. 6973:4-6974:7 (Howitt).[366] This analysis was used to justify electrification in AFE S020.

Draft Report Independent Project Analysis, Inc. (Nov 2003)

585. Ex. SOA-287 is a Prospective Evaluation of the SR Project done by Independent Project Analysis, Inc. (IPA) in November 2003.[367] The analysis uses IPA's Project Evaluation System model. The analysis assesses the status of the project and identifies

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[365] Ex. ATC-245 is undated. The joint chronology dates it to November 13, 2003. Ex. J-2.

[366] *See* State IB Appendix at 290.

[367] The document has a "draft label." The final was not produced in this record. The document does not have a date on it. The chronology submitted by the parties (Ex. J-2) dates it to November 1, 2003. However, the e-mail dated November 19, 2003 (Ex. SOA-489) provides a more reasonable date. In the email D. Ahrens sends the IPA report to a number of people and requests their feedback. He states that they will owe IPA feedback by next week. "The final report (which I'll feel obligated to get to the owners will come out approximately Dec. 3rd." *See* the reply, *infra*.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

areas of concern. It notes that any scope changes to the project may alter or invalidate the results of the analysis. *Id.* at 2. At the time the report was issued the SR Project team was working on completing its authorization package. *Id.* at 3. The document states that based on the data collected at the interview of October 22, 2003, the status of the project definition, or Front-End Loading (FEL) is currently in the Poor range. "IPA's historical data show that projects of similar complexity authorized with a Poor level of project definition have much more variable cost and schedule results than projects authorized with Good levels of definition." *Id.* at 3.

586. The analysis concluded that the primary drivers for the Poor rating were gaps in the project execution planning and engineering status. The engineering status was lagging because the scope and cost estimates for the automation part of the project are not completely defined. *Id.* at 3. It notes that the automation portion is 20% of the total cost estimates. The gap in project execution planning is associated with the development of the project schedule. The schedule was not resource loaded or the construction phase was not resource loaded. The document notes that the project is using two out of nine or 22 percent of applicable Value improving practices. *Id.* It notes that the construction costs and field cost are lower than industry average. Additionally, the report states that the detailed engineering phase has just started, construction is to start on May 1, 2004 and completion is estimated as October 31, 2005. *Id.* at 4. Initial long lead time equipment procurement has been started. *Id.* at 9. The report notes that modular construction work will be executed under a lump-sum contract. However, construction work dealing with installation of the modules will be on a cost-plus, fixed-fee contract. *Id.* at 9.

587. In terms of the Team Development Index IPA rated the SR team in the Fair/Poor range. It stated that the team could improve by identifying the major problem and risk areas associated with the project and assigning team members to be responsible for developing mitigation plans. "Second, the team will attempt to adhere to the Alyeska Management System (AMS003) project implementation process. However, AMS003 is designed for the execution of much smaller projects. The project team will use elements from each of the owner companies' project implementation processes in addition to AMS003." *Id.* at 21.[368]

588. IPA recommended improved project definition including attaining a best practical level of FEL prior to progressing into execution. *Id.* at 6. Most important, IPA recommended that engineering and construction activities be resource-loaded. Additionally, it was recommended that the automation scope be finalized, mitigation

[368] The questionnaire answer (Ex. SOA-190 at 8) and the statement above are inconsistent. The questionnaire states: "However, we are currently following AMS-003 without modification, . . ." The Joint Chronology dates this exhibit to November 6, 2003. Ex. J-2 at 17.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

strategies should be developed and the cost for construction labor had to be reassessed. *Id.*

589. In the conclusions and recommendations section the report notes that the SR "would incur a greater risk of slipping the planned schedule and overrunning the estimated costs if it were to progress into execution with the current level of project definition. In order to reduce the risk of missing the cost and schedule targets, the team should focus on finalizing the project definition work prior to moving into execution. *Id.* at 35. The report recommended improving definition of the project prior to progressing into execution. "Most important, resource-load the engineering and construction activities. Resource loading will bring a better understanding of the required construction labor hours to complete the job and, consequently, will lead to a better cost estimate." Additionally, it recommends "[f]inalize the automation scope and include the automation estimate in the overall cost estimate." Finally the report recommends a reassessment of the costs for construction labor, stating that the costs are significantly lower than industry, and that it is possible that the number of labor hours is underestimated." *Id.*

Email from Mike Tudor November 12, 2003

590. Mike Tudor (Exxon) wrote that he was quite under-whelmed by the last review of the SR project in a review he had with his folks. Ex. SOA-183. This email to Meg Yaege at Conoco and Al Bolea at BP gives them a heads up of Tudor's feelings at the time. He states there are many issues but summarizes just three:

- the obvious significant scope and cost growth from Gate 2 to Gate 3, as yet not fully explained and reconciled
- the "lumping" of savings that to-date makes it impossible to determine the incremental return on the last increments of investment
- the apparent abandonment of the "do-nothing" or "hybrid" case from a development perspective, that seems to make it impossible to accurately compare the proposed project versus the next-best alternative. (There was a clear commitment from the February 2003 Owners meeting to complete this work).

Id.

591. He further states that the project had a "pretty rough ride through our senior management at Gate 2 based on "marginal" return given it is a "partial revamp project in a mature area." *Id.* Additionally, he says there is a possibility they will not support the project at the next gate. Further, he states: "The ability to be able to: (1) clearly reconcile and justify cost growth between Gate 2 and 3, and (2) clearly and accurately identify the proposed project's return relative to

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the next-best alternative, are prerequisites within our Company and we won't recommend moving forward until the project team delivers this." *Id.*

November 19, 2003 Presentation to Owners Committee

592. The presentation talks about the vision (reduce costs, simplify facilities, renew assets, and automate). Ex. SOA-136 at 5. In the 2003 objectives, it lists complete preliminary engineering. The sub-bullets to this are: optimized design and project plan; preliminary power options; cost estimate within +/- 15%; compare to "hybrid case" +/- 30%. *Id.* at 6. In the program scope slide it list pump stations 5 and 7 as rampdown stations. *Id.* at 10. The document states that the SCADA system replacement is separately funded. *Id.* In the review of options slide it lists inertia as a lifecycle maintenance and replacement of existing equipment; hybrid as being automation of existing pump stations; electrification simplifies, renews and automates the pump station; direct turbine drives was previously presented to the owners. *Id.* at 12. The station configuration is described as 3, 3, 3, 3, parallel pumps at PS 1,3, 4, and 9 with standard 6500 nominal HP motor with 1.15 service factor, all pumps motors and VFDs are identical. *Id.* at 21. The operating facilities will be unstaffed. *Id.* at 42.

593. In terms of savings the document states that field staff has savings as a result of, operations staffing having been eliminated and field support and maintenance having been consolidated. *Id.* at 45. The support staff will be removed from the field and reduced as a result of less equipment and infrastructure. *Id.* The total reduction in contractor staffing is 185 and Alyeska employee staffing is 188 for a total of 373 with an annual O&M savings of $51 million and 20 year O&M savings of $1.2 billion.[369] According to page 59 the total 20 year savings for electrification are $1.7 billion ($1.2 billion in O&M and $491 million in major maintenance).

594. The potential cost of delay for one year considered the following: fire and gas upgrades, RGV MTU upgrade, annual O&M savings, engineering, program management and loss of tax bonus (the Jobs Growth Tax Reconciliation Act of 2003 allows taxpayers a 50% bonus (accelerated depreciation) for qualifying assets.)[370] *Id.* at 71.

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[369] Field staffing would be reduced as follows: in operations from 105 to 4; field facility maintenance from 134 to 92. The staffing for ROW/OSCP would be about equal to present. *Id.* at 52. The Fairbanks Maintenance Center linewide maintenance organization would be reduced from 79 to 57 and the support groups in Fairbanks and Anchorage would be reduced from 763 to 555. *Id.* at 52.

[370] The legislation allows, for qualified property, a tax deduction of 50% of the cost in the first year, the remaining 50% cost over the normal taxable life and schedule. Ex. SOA-13 at 10.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

595. The project execution plan included competitively bid lump sum contracts. *Id.* at 76. The schedule on page 77 contemplates the start of transition engineering by November 1, 2003; the long lead PO issued by December 1, 2003; by March 1, 2004 the authorization for equipment manufacture would issue; work would continue through summer 2004; major equipment at fabrication shops by fall 2004; module piling at PS 1, 3 in winter 2005; module shipment, start interconnect by spring 2005; mechanical completion Oct 05- December 15; start up November 05- January 06. However, it is noted that the next page states that Gate-3 deliverables will not be completely finished until 2Q 04. *Id.* at 78.[371] In the conclusions it is pointed out that the schedule is a challenge. *Id.* at 88. Among a number of recommendations "finalize agreement for PS 1 by February 2004." *Id.* at 89.

Email November 22, 2003

596. An e-mail from John Barrett to the project team states that they need IPA to come back and do an update. "If we send this to the Owners, we will be explaining it forever. We had the review too early." Ex. SOA-489.

Pipeline Reconfiguration Economic Evaluation Report December 1, 2003

597. This report mentions the fact that after twenty-six years of operations, existing station equipment is approaching the end of its economic life. Ex. SOA-13 at 3. The report distinguishes electrification (PS 1, 3, 4 and 9 which will get new electric-motor-driven pumps in addition to control system upgrades) from Reconfiguration (upgrades to pump station equipment and control systems at most pump station locations) and states that electrification is a subset of Reconfiguration. *Id.* at 3. It recommends electrification of all four pump stations as the higher after-tax benefits. It also states that it was not quantified, but the next best alternative is likely direct turbine-driven pumps in new modules. *Id.* at 4. The savings in this report were calculated by comparing the various alternatives to a forecast for the status quo case called Inertia. The Inertia case represents the company's forecast of spending if Reconfiguration did not occur.[372] *Id.*

598. The Inertia case assumed lifecycle maintenance and replacement of existing equipment, as required and includes O&M savings due to business efficiencies. In this alternative there are no savings from SR. According to the document this alternative has

[371] Page 82 of this document mentions obsolescence/degradation risk for PSs 1, 3, 4, 9 and power generation (Garrets) obsolescence. Additionally, there is a bullet point on air quality forced obsolescence for PS 9. There are no studies in this record to back these bullet points.

[372] The savings attributed to the various alternatives are incremental to the Inertia case. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the highest predicted cost and the lowest certainty. *Id.* at 5. Hybrid assumes control systems upgrades for partially unstaffed operations and other lifecycle maintenance and replacement as required. It provided no scalability and Rovers would observe pump station equipment centrally operated from the OCC. This alternative has a slightly lower cost than Inertia but has a significant amount of uncertainty concerning future maintenance and operation costs. *Id.*

599. The direct turbine drives would have new modular equipment, controls and automation but no VFDs or electric motors. "This alternative was not evaluated to the same level of accuracy as Reconfiguration: but the savings, reliability, and environmental benefits are similar to the recommended alternative. In this scenario capital costs are lower and ongoing savings are slightly lower than Reconfiguration… This alternative would require new preliminary engineering efforts, which would cause a delay in project implementation and $90-100 million in lost benefit. This appears to be a viable alternative with lower investment costs. However, the lost savings due to a timing delay are significantly greater than the cost savings." Therefore, this was not recommended. *Id.* at 5-6.

600. Reconfiguration is described as pump drivers replaced with new modular, automated, electric-motor-driven pumps and VFDs. PS3 and 4 power is provided by new turbine generators. PS 1 and 9 power is provided by a local electric grid. Control systems are upgraded at all stations to allow for remote operation. New modular command or communications modules house the upgraded control equipment. Pump stations are completely unstaffed. Maintenance and spill response systems are regionalized. The document states: "This alternative offers the best NPV, IRR, environmental benefits, scalability for throughput changes, and certainty about future costs. This is the recommended alternative. This alternative is the foundation for the company's long-range plan; significant organizational momentum exists for this alternative. *Id.* at 6.

601. In terms of savings the document states that the savings were estimated through 2013. Beyond 2013, they used average savings. *Id.* at 7. PS 1 is described as the most complex and PS 9 the least. PS 3 and 4 are combined for the evaluation as the operating portion of the stations is nearly identical. Changes at PS 5, 7 and rampdown stations are not large enough to impact organizational savings.

602. The schedule for unidentified major maintenance is different in this document (Ex. SOA-13 at 9) than SOA-141 (Shotts email "unidentified major maintenance"). Due to the fact that the equipment has been in service over 25 years, and new types of maintenance are anticipated, a provision for unidentified maintenance was added. The graduated provision in Ex. SOA-13 is 10% in year two, 30% in year three and 50% thereafter. The approach was used for all alternatives." *Id.* No explanation was given for either schedule.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

603. The document states that Alyeska perceives a high level of uncertainty around the Inertia and Hybrid forecasts. It states that the electrification forecast has a higher confidence because much of the existing equipment will be removed from service, and the new equipment reliability has greater certainty and predictability. *Id.* at 9.

604. The analysis assumed the Owners will continue to provide energy "in-kind" to PS 1, 2, 3, and 4. Historically, the energy source had been natural gas provided in-kind. *Id.* at 10. However, it also assumes a commercial rate of $0.054 per kilowatt. *Id.* Exposure for power at PS 9 is being worked on and trying to be reduced. However, the assumption for purposes of the study is approximately $1.23M per year for a Static Var Compensator. *Id.* at 11.

605. According to the study, an essential element of the program is completion by the end of 2005. This is due to the fire system modifications for existing facilities which will have to be done in 2005 and the bonus depreciation is due to expire also. The estimated impact of a 1 year delay is around $100 million (fire and gas system modifications, lost bonus depreciation deduction, lost organizational savings, additional project management costs, and loss of fixed price materials bids). *Id.* at 12.

606. The document notes that the Hybrid alternative was not as thoroughly evaluated as the Reconfiguration alternative. Therefore, the confidence level for Hybrid cost and savings estimates are lower than those of the Reconfiguration alternative and Electrification options. *Id.* at 12. This document states that Final Design Engineering has not been done yet. *Id.* at 13.

607. Concerning staffing changes this document estimates total Reconfiguration staffing reductions as 347 (181 Alyeska/166 Contractors). However, the figure for PS 1, 3, 4, and 9 or Electrification is 285. The difference between 285 and 347 is 26 for PS 5, 18 for PS 7 and 18 for Rampdwon stations. *Id.* at 14. When other efficiencies are included (PS 11 & 12, efficiencies in business cycles, other changes) the total goes up to 414 staff reductions (67 for other changes). *Id.* at 14.

Larkspur Report

608. Larkspur performed a review of the preliminary engineering estimate for SR on December 9, 2003. Ex. SOA-222. Larkspur reviewed the estimate and compared it to historical Alaska costs. The report concludes that it does not believe the accuracy level of the estimates fall within the stated accuracy range of +15%/-15%." *Id.* at 1 and 3. According to Larkspur, a major item missing from the engineering basis was a process/mechanical equipment list. "This is an important document because it provides a checklist for estimating to make sure that the estimate contains each piece of equipment and the accompanying description provides a basis to insure that the estimator picks up the correct equipment with all ancillaries." *Id.* at 2. It notes that the labor hours to install the "design allowance materials" were not included in the estimate.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

609. Larkspur also finds issues with the project execution plan as being too general. More detail should have been added to "address items like module assembly/transportation, who and how the busing to the sites would be handled, and any coordination or sharing of resources between the sites." Additionally, Larkspur states: "The estimate was segregated into direct hire and subcontract costs, but did not seem to follow the construction work packages described in the Execution Plan. For example some activities were estimated as subcontract for no apparent reason. Considerable effort may be needed to recast the estimate into a document that can be used for project costs control." *Id.* Moreover, they found many estimate inconsistencies between the two company portions of the estimates. *Id.* at 3. The Hinz estimates did seem to have more Alaskan rates, unit rates, etc. *Id.*

610. Concerning the calculation method Larkspur again finds concerns. For instance, it found that a summary "sheet that clearly totaled all direct labor hours and labor, indirect hours and labor, assembly and fabrication hours and labor and material costs was not provided." "We are also concerned that a spreadsheet type program was used to rollup such a complex estimate." "We would recommend that a commercial estimating program be used when the definitive estimate is developed." *Id.*

611. Dealing with the estimate reviews Larkspur found that the "All-in Craft Wage Rate" was too low. *Id.* at 4. The indirect costs were also low. *Id.* Moreover, for PS 3 and 4 Larkspur notes that there was insufficient time estimated for field erection of the platforms for the generators. *Id.* at 5. The same additional module setting requirements were considered for PS1 and 9. *Id.* at 5. The unit man-hour rates for installation of platforms, handrail, grating, pipe manifold structural assembly, etc are low. *Id.* at 7.

612. Larkspur found that the SNC building estimate for existing buildings is a +/-30% estimate. "This scope of work has not been clearly defined in detail and relies heavily on operations support. Estimate details are on a very summary level and man-hour rates may not cover the relocation and set up time required for these smaller tasks. Risk of contamination and disposal costs for therminal and any brine is excluded from the estimate." *Id.* at 7. Additionally, Larkspur concluded that the module fabrication estimate was low. *Id.* For piping costs Larkspur is certain that additional scope will be required that is not covered in the estimates. *Id.* at 9. Concerning home office costs, Larkspur is concerned that the ratio of 60% engineering to 40% support is too low. *Id.* at 12.

613. Larkspur concludes by stating that it has major concerns that the project as currently designed could be built for the current estimate value. *Id.* at 13.

JPO Concerns December 16, 2003

614. On December 16, 2003, the Joint Pipeline Office by letter, conditionally approved the SR preliminary design submission. Ex. ATC-233. This was in accordance with Stipulation 1.7.2.1 of the Federal Agreement and Grant of Right-of-Way and the State of

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Alaska Lease for TAPS. The conditions would have to be met before application for Notices to Proceed to cover construction. *Id.* A number of issues were raised in the letter including the schedule. *Id.* at 4. The document states that the "schedule is highly aggressive and optimistic. This means that the major milestones should be considered to have a large measure of uncertainty. *Id.* Additionally, the design methodology was insufficient. *Id.* at 5. Other deficiencies included the "SR Design criteria where only 20% of the wall removed and the building goes cold would not require a fire protection system. Such a design does not meet State building code requirements." *Id.* at 9.

615. The JPO notes that SR is scheduled as several projects. "JPO cannot fully understand these without access to their Work Breakdown Schedule (WBS), which will tie them together." *Id.* at 13. Next, it states that the Preliminary Engineering uses the term "abandoned in place. Buildings abandoned in place present a hazard to buildings on site in use under SR." *Id.* at 14. It recommends that a pump plot plan be provided and final determination of which buildings will assist in determining if "design complies with International Building Code (IBC) requirements. *Id.* at 14. Moreover, the letter states that "[i]t should be noted that existing fire systems were included in all areas of the core buildings and hallways due to foam insulation being used in the metal panels during construction." It goes on to state that "[t]his section calls out the use of UBC, UFC and the UMC. The State of Alaska has adopted the IBC, IFC and the IMC for design and instructs to revise accordingly." *Id.* at 15.

616. At page 21 it notes that they are still trying to figure out the power supply issue for PSs 1 and 9. Further it questions the use of a 20-year versus a 30-year evaluation of life cycle cost on equipment and states that the information provided does not adequately support the proposed design. *Id.* Moreover, the letter notes that the terms design basis and design criteria are used inconsistently throughout the Phase I submittal and requires clarification. *Id.* Grounding and design basis conformance to ANSI/EEE Standard 142 is also noted as an issue, especially in light of the effects of permafrost and seasonally frozen ground conditions on grounding. *Id.* at 22. International building code requirement issues were also raised for buildings which were going to remain, including notation that buildings abandoned in place "present a hazard to buildings on site in use under SR." *Id.* at 23. Code issues, fire alarm issues are noted on page 24.

Risk and Cost Probability Distribution Analysis – December 17, 2003

617. The risk analysis favors electrification as compared to inertia. The prediction is a very high probability of achieving better than expected results in annual operation savings and major maintenance savings while predicting a moderately high probability of executing the project at lower than expected costs. Ex. ATC-236 at 8. P. Flood of Conoco assisted in designing the risk analysis model. " If project quality is poor, expected efficiencies in maintenance and support efforts may not be fully achieved, and/or the company may not be able to operate the stations unmanned. Meanwhile, construction cost is affected by uncertainty in scope and cost for installation and by

20140227-3052 FERC PDF (Unofficial) 02/27/2014

uncertainty in the supply of equipment and labor. Additional uncertainties for electrification include transition costs and quality of management of change during transition." *Id.* at 2. Note that this analysis was at a high level. *Id.*

AFE S020 Submitted for $242 Million

618. On December 18, 2003, Alyeska submitted AFE S020 to the Owners for approval. This was for Pump Stations 1, 3, 4 and 9 Electrification and Automation. Ex. SOA-591; ATC-237. The AFE requested $242 million ($206.3 million in capital, $35.7 million expense) for the design and construction phase of the Pipeline Reconfiguration effort for PSs 1, 3, 4, and 9. Ex. SOA-60 at 2. The request states that the cost and savings are based on the work occurring concurrently at all stations to achieve efficiencies. *Id.* The project will allow unstaffed operation and significantly reduce operating expense and future major maintenance exposure. *Id.* at 5.

619. In the overview of why the project is needed it states, the existing "station equipment is approaching the end of its economic life." *Id.* at 4.

620. PS 1 is estimated to cost $42.5 million and "will be connected to the North Slope electrical grid via a 69 kilovolts (kV) tie line and substation rated at 21 megawatts (MW). The existing mainline units will be replaced with variable frequency drives (VFDs) and electric motor driven pumps in truckable modules. Two of the existing 3 booster pumps will be retained and repowered with VFDs and electric motor drivers." A 4.5 MW back-up generation system will provide power for minimum flow capability for cold restart. Ex. SOA-60 at 5.

621. PS 3, 4, and 9 are estimated to cost $43.2 million, $44.9 million and $33.8 million respectively. *Id.* at 6-7. PS 3 and 4 will have on-site generation supplied by two turbine generator packages. The mainline units will be replaced with VFD drives and electric motor driven pumps in truckable modules. 750 kW lifeline/back up generation systems will provide power for unplanned and scheduled outages. *Id.* at 6. The Galbraith Maintenance and Response Base will be at PS4 adjacent to the pump station facilities. It will have living quarters and camp, several warehouses, shop and OSCP buildings, and an office.

622. According to the document, PS 9 will be connected to a local utility high voltage transmission system. The mainline units are replaced with VFD drives and electric motor driven pumps in truckable modules. A 4.5 MW back-up power generation system will provide power for minimum flow capability to avoid a cold restart scenario. It will include an OSCP building. *Id.* at 7.

623. The Maintenance and Response bases will be at Prudhoe Bay, Galbraith, Prospect, Fairbanks, Glennallen and Valdez. The bases will be separate from the pump stations, which will be unstaffed and remotely operated by the OCC. *Id.* The AFE includes some

20140227-3052 FERC PDF (Unofficial) 02/27/2014

funding for spare parts. To wit, component parts for one VFD, one pump and one rotating element, two motors; one turbine generator rebuild kit and critical control system components. Concerning security the document talks in terms of doing it remotely. *Id.* at 8. There is a $10.4 million contingency which includes contingency for supplemental critically skilled workers (contractors). Additionally, there is a $16.4 million contingency for unidentified activities. *Id.* At page 9, the exhibit states that at least 75 buildings will become non-operational.

624. Concerning project costs the document points out that they were conceptualized to be a major driver of Electrification uncertainty, but there is a relatively high level of certainty around the construction cost estimates. *Id.* at 16. The risk analysis estimated the investment costs to range between $219 million and $258 million with a mean value of $238 million. It states that there "is a 90% probability that the investment costs will be less than $248 million." *Id.*

625. The project economics describes the Net Present Value (NPV) and IRR of three electrification options. *Id.* at 13. The chosen option is electrification of four pumps as described above. In addition, there is an economic comparison between electrification and hybrid. Hybrid is described as automation of existing equipment to allow partially unstaffed operations. *Id.* at 13. The document states that reconfiguration offers significantly better economics than Hybrid or Inertia. Electrification is $153 million better than Hybrid. *Id.* at 13. On page 14 there is a chart showing the IRR and NPV of the electrification and Hybrid options. The NVP analysis assumed 2.5% inflation, 11% discount and 41% tax bonus depreciation. *Id.*

626. In terms of cost savings the document compares partial electrification (electrification 3, 4 & 9) to the electrification program (electrification 1, 3, 4 and 9) and states that the electrification program offers the highest value and savings of all alternatives evaluated. *Id.* at 9. This is in terms of annual O&M and MM savings over 20 years. *See* chart at 9.

Discussion 2003

627. By January 15, 2003, notes from J. Johnson show that "hybrid is dead." Ex. SOA-745. As shown above since October 2001, the Carriers exhibited entrenchment with the electrification course, and as Staff points out, negligibly studying utilization of the existing, reliable, equipment. Staff RB 36. Despite previous studies showing that the Carriers could achieve savings by automation of the legacy equipment, the Carriers adopted electrification in October 2001, an approach that had been previously rejected in the prior studies, without explanation or reasoned support. This was contrary to industry practices. Through 2003 the Carriers secured contractors for preliminary engineering, conducted preliminary engineering for electrification and prepared AFEs to fund the project.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

628. The Carriers failed to perform significant analysis during preliminary engineering to validate or not the conceptual engineering studies, i.e. risk analyses of conceptual engineering. Ex. SOA-1 at 126-27. This is contrary to standard industry practices and the Carriers own standards. Ex. SOA-1 at 8:17-21. This approach exacerbated the flaws in the conceptual engineering studies which were based on probabilities and subject to change. Ex. SOA-299.

629. According to industry practice once conceptual engineering is complete then you move on to preliminary engineering. Conceptual engineering should have been done in such a manner as to ensure sufficient project definition prior to authorization or sanction.[373] Ex. SOA-1 at 128:15-16. Conceptual engineering is part of the initial steps to front end loading (FEL). Ex. SOA-425 at 41.

630. As C. Sullivan testified, FEL is a standard industry process that is "structured to ensure that sufficient project development and engineering are performed in the early phases, prior to project sanction, to ensure that engineering changes are minimized during the later phases of project development." Ex. SOA-1 at 137:18-138:1. Alyeska's AMS-003 Project Management System, which is the protocol for construction projects follows FEL. In AMS-003, FEL includes completion of the evaluation Phase (conceptual and preliminary engineering) and the Planning and Development Phase, which includes developing formal engineering designs to the issue-for-construction (IFC) drawings, refining and further developing cost estimates (+/- 15%) and schedules; it may include the initiation of procurement of long-lead items. *Id.* at 133, Fig. 78 and 136:8-11. AMS-003 establishes that the Planning and Development Phases must be completed before implementation. *Id.* at 133, Fig. 78. C. Sullivan further testified that AMS-003 is consistent with generally accepted project development practices in the pipeline industry. *Id.* at 136:16-18. This testimony is given significant weight.

631. In preliminary engineering additional studies and evaluations are conducted, increasing project definition to the point of cost estimate +/- 15 to 30%. Ex. SOA-1 at 7-8. Once preliminary engineering is complete, a project moves to front-end engineering and design, and detail engineering, where final engineering drawing and issued-for-construction drawings will be developed. Ex. SOA-1 at 128:7-12. At this point the cost estimates are in the range of +/- 10 to 15%. All of these steps are part of FEL, and have to be completed prior to project implementation. Ex. SOA-192, SOA-1 at 130:17-18.

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[373] Conceptual engineering (often the first phase) broadly identifies various alternatives that may meet the business/project objectives. Each alternative may be developed to include sufficient project definition to support a conceptual cost estimate, which typically falls into the accuracy range of +/- 50 to 100%. The cost estimates at this stage are referred to as rough order of magnitude (ROM) estimates. Engineering deliverables at this stage are not issue-for-construction quality and typically include very general technical definition, such as plant capacity or major equipment capacity, product requirements, and ROM estimates. Ex. SOA-1 at 126-127.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

This process has to be undertaken in order to lower costs and have a successful project. Ex. SOA-1 at 128:17-21. As C. Sullivan testified, "it is well established in the engineering and construction industry that the ability to affect overall project cost is highest in the early phases of project development, prior to sanctioning costly procurement and construction activities." Ex. SOA-1 at 140:20-141:1, 129:20-130:2. The Carriers did not follow the industry standard FEL process. They rushed preliminary engineering which exacerbated the mistakes made in conceptual engineering, missed key activities, and did not properly estimate project costs, schedule or scope. These actions are not what a reasonable utility manager would have done and are thus not prudent.

632. Experts in the field were not consulted and conflicting viewpoints including operations personnel viewpoints were ignored. Alyeska operations and engineering personnel were ignored early on, company experts were not consulted early on or if they were, their input was dismissed because it did not conform to preconceived views about the answers, including costs. Ex. SOA-280. The State is correct that without these resources reasonable cost estimates cannot be created.

633. Alyeska personnel tried to warn those in the decisional roles that the conceptual estimates did not reflect reality. For example, J. DeHaas noted that the estimates were low by a large amount, there does not seem to be nearly enough included for engineering, site construction and all the other activities that must take place. Ex. SOA-21. Additionally, he objected to the basic design of SR. "In fact I think portions of it quite absurd, to put it in plain language". Ex. SOA-187. He also challenged the conclusion that Electrification would be easier to implement than other options. He wrote, that the "electrification scheme is the least standard of any of the concepts. It requires a mix of equipment and concepts at two pump stations, which is more non standard than any other concept, including a hybrid concept." Ex. SOA-284. He also challenged the costs both of maintenance and the project and objected to the lack of use of the internal experts as opposed to external contractors. *Id.* at 2.

634. When internal personnel challenged the work that had been done, they were "shut down by Kevin Brown and Joe Riordan [BP] who spoke with passion but not with sound engineering justification." Ex. SOA-284. Barrett was aware that there were lots of Alyeska operations people raising concerns with SR. Tr. 5809:15-17. Howitt was aware that Alyeska employees referred to the difficult issue of integrating electrification into the existing plant as changing a jet engine in mid-flight. Tr. 4606:4-11; 3022:25-3025:14.

635. In another email J. DeHaas was recognized as a "world wide expert in rotating equipment." Ex. SOA-140. However, he was not a part of the process. In the email cited above he states:

> I find it strange that this project is all about rotating equipment, and from the very concept stage the Alyeska rotating equipment engineer was not involved. Just where did the expertise come from I wonder? Was it a consultant(s)? What were their credentials? Later I was directed to support

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> the rotating equipment portion of the project. Again it is all about rotating equipment, and I've only been asked to review some specs. In some cases, in particular with SNC Edmonton, it has been difficult to get my points across. Very difficult I would say. It appears Alyeska representatives have little to offer to that bunch, per current project organization.
> …
> I am frustrated and very much so. What I am so frustrated about is that this industry seems to use its own inhouse technical experts more and more very ineffectively. It is almost as if they are viewed as a liability, rather than an asset. As such the present mode of doing things is to leave your own experts on the sidelines, even if you have them, and go hire consultants and/or contractors. Let them do your work, and let them tell you what you want to hear. If your own inhouse [sic] expert has something contradictory to say, ignore it. In the end these projects are all about proper application of technology, and this seems to come last.

Ex. SOA-284 at 2-3.

636. L. Monthei,Alyeska's Vice President of Engineering and Projects agreed, "[f]our of our most knowledgeable Engineers are not convinced this makes good economic sense and I agree with their concerns. The configuration will cost $ 12-million more, will be less reliable, and more costly to maintain. Of more concern to me is that the Engineers feel their concerns were not considered and that they were shut down by Kevin Brown and Joe Riordan who spoke with passion but not with sound engineering justification." Ex. SOA-284.

637. Jones the Senior Vice President, Operations & Maintenance also told management about problems in October 2003. In an email he wrote:

> They believe there are errors in the analyses, including present value numbers, but no one on the project team apparently wants to listen, or we can't change course now because it is too late. They are frustrated and find it incredible that "hired vendors" are apparently in such complete control. They are frustrated because they have had no real influence on the proceedings, and there is no time for peer reviewing of work and /or carefully checking things along the way. . . . We need to remember these are quality people saying this. And the noise is really in a lot of places not just engineering.

Ex. SOA-280.

638. Alyeska employees were ignored and this created the impression that the decision to sanction electrification was preordained. In the October 2003 email, Jones identified this dynamic as common breakdown: "The company experts or clients are not consulted

20140227-3052 FERC PDF (Unofficial) 02/27/2014

early on, or if they are, their input is dismissed because it does not conform to preconceived views about the answers, including costs. *Id.* He also stated that costs and schedule pressures to make the project "a go" are permeating interactions with client teams, "giving the appearance that the project team is the decision maker, and turning folks off . . . Owners staff are more connected than the client teams and perceived as part of the culture problem. *Id.* Turnipseed also testified that there was discontent among the employees on the receiving end of strategic reconfiguration, that they felt they were not being heard. Ex. AT-429 at 27 and 38-39. V. Heibert expressed the same sentiments.[374] A Conoco engineer who reviewed the project prior to sanction stated: "[t]he wisdom of electrifying PS3/4 was not fully explained. We question whether turbo-generator/electric pump is more reliable than direct drive turbo-pump." Ex. SOA-260.

639. The State points out that the only evidence cited by the Carriers to support their claim of Alyeska involvement in SR preliminary engineering merely shows that one Alyeska employee, M. Veit, was assigned to work on the SR project in December 2003. Carriers IB 162. However, as the State correctly points out, SNC-Lavalin delivered the preliminary engineering report to the SR PMT in December 2003. State RB 58; Ex. ATC-208. Thus, it is correct that Veit who conducted a 'high level review of the …. Pump Station Electrification Project Drawings" sometime in December 15, 2003, had any impact on the preliminary engineering relied on by the Carriers to sanction SR. Ex. ATC-232.

640. The Carriers also argue that DeHaas endorsed the recommendation of Sulzer (for reconfiguration of the pumps) to support their claims that there was operations involvement in preliminary engineering. However, the State is correct, the cite for the DeHaas "endorsement" is hearsay, since it is an email from B. Howitt. Ex. ATC-229. There is no evidence in the record of DeHaas making such a statement. Moreover, the State is also correct that "endorsement" is hardly involvement.

641. The next exhibit is more interesting. It is again, a January 5, 2004, email from B. Howitt stating that operations management and engineering reviewed the turbine/generator recommended package from an O&M standpoint. Again on hearsay, Howitt reports that "[o]perations fully endorses the recommended award to Siemens." Ex. ATC-249. This hardly represents close involvement in the equipment selection as the Carriers maintain. Carriers RB 59. In a previous email dated December 29, 2003 from DeHaas he notes, the "best proposal is that submitted by Siemens, therefore I am in agreement with SNC's work. He also notes that the Cyclone is not very far along in its life cycle, having been on the market some 4 years or so. It has experienced one notable problem, that being premature failure of the 1st stage turbine blades." *Id.* Again, agreeing with SNC is hardly being involved in the project.

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[374] V. Heibert is a recognized technical expert in control systems, automation, and SCADA systems. Ex. AT-405 at 13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

642. The Carriers concede the point that DeHaas was not in favor of replacing the Avons and that his opinions were not always accepted. Ex. SOA-19. The Carriers cite SOA-22 to support their claim that DeHaas has now turned around and favors SR. However, this email is dated January 2007 and in light of the Carriers allegations concerning hindsight documents this email will be discussed below in the year 2007. Suffice it to say that DeHaas is still critical of SR in 2007. The Carriers cite 6 other exhibits to support the claim that DeHaas views were solicited. Carriers RB 59 n. 75. However, no one in this case has argued that his views were not solicited. The Carriers concede that in the most important point the Avons vs. electrification his views were rejected. A reasonable utility manager would have undertaken adequate studies to determine the reasonableness of replacing perfectly working legacy equipment with electric MLUs.

643. The employee warnings were ignored and the fact is that the estimates (costs and savings) were significantly inaccurate. The exclusion of the advice of knowledgeable people from within the organization during preliminary engineering was against industry practices. Ex. SOA-275 at 36:10-41:17. *See generally*, SOA-425 at 36:4-5. If they had listened to the operating personnel they would have gained insight into the issues with the engineering of SR. For instance, they would have known that the engineering design was not in compliance with regulatory requirements. In fact the JPO letter dated December 2003 alerted the SR team to the fact that the preliminary design was using the wrong regulatory standards. The fact is that the design had to be revised throughout the first year of project construction. If the expertise of the internal experts had been followed a proper preliminary engineering study would have been done. Thus the Carriers actions in this regard were not those of a reasonable utility manager and were imprudent.

644. The Carriers claim that preliminary engineering 'began in early 2003 when the Carriers approved Alyeska's request for $7 million to fund the developmental activities . . . and continued until December 2003 when Alyeska submitted AFE 2020, requesting project sanction." Carriers IB 130. The evidence in this record can pinpoint the dates with more accuracy. Preliminary engineering started on April 29, 2003. Ex. SOA-232. This work was completed on November 3, 2003. Ex. ATC-208 (Preliminary Engineering Design Report).

645. The Carriers also claim that during preliminary engineering, "everything was done that was reasonably believed to be necessary. The project as submitted for sanction was well defined and fully supported." Carriers IB 130.[375] However, the evidence in this

[375] The Carriers also claim that there is no mention of other significant steps the Owners took in 2003 to ensure the project was ready to proceed such as briefing the Governor's and State Attorney General's offices on the SR project. Carriers RB 67. It is found that this is irrelevant to the decision in this case.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

case shows that during preliminary engineering cost estimates were not developed. In an email from Ahrens to Barrett dated May 27, 2003, the following is admitted, "[s]ince we do not have any numbers to replace the conceptual, and in order to be consistent with the budget and AFE philosophy, I suggest we add at least 30% to Electrification and Control Systems upgrade numbers." Ex. SOA-561. Therefore, they were using conceptual engineering estimates for the first AFE estimate. This is not the behavior of a reasonable utility manager. The AFE for preliminary engineering specifically stated that preliminary engineering was to develop "[b]etter estimates for equipment, construction costs, and savings" and an "[u]pdated cost estimate with +/- 15% accuracy." Ex. ATC-165 at 6. As a result, it is concluded that the Carriers did not follow their own procedures and they sanctioned the project with cost estimates that were not fully developed.

646. The Carriers finished preliminary engineering in six months and five days to be exact,[376] to obtain the presumed savings associated with a 2005 start-up. A more realistic time frame for preliminary engineering would have been 18-30 months (for a project with the complexity of SR and improper conceptual engineering), normal preliminary engineering design could have been accomplished in 12-18 month (if proper Needs Assessment and Conceptual engineering had been done). Ex. SOA-425 at 42-43. Sanders testimony in this regard is given significant weight. He testified that a reasonable pipeline manager would provide sufficient time to complete at least preliminary engineering properly prior to determining whether to sanction the project based on cost and viability. Ex. SOA-542 at 52:19-21. "The level of engineering would entail reviewing and testing each of the underlying assumptions of the project. It would study in detail each critical component of the project. This kind of Preliminary Engineering and Front End Design (FEED) work . . . is crucial to accurately establishing the scope of the projects. Without a clear and fixed scope that defines the amount of work that needs to be done, accurate estimates for work are impossible and there are likely to be substantial cost overruns and schedule delays." *Id.* at 52-53.

647. Due to a number of reasons, including the unrealistic schedule and inexperience of the PMT, the Carriers failed to perform a number of significant preliminary engineering activities. For instance, the Carriers failed to secure power supply agreements before sanction for PS 1 and 9. Ex. SOA-172. This is not prudent. A reasonable utility manager or owner would have locked in service and price terms with the electric power supplier prior to sanction. These two pump stations depended on the availability of reasonably priced, reliable service from third parties. Ex. SOA-542 at 57:9-14. The subsequent contracts required supplemental funding of millions of dollars to purchase and install generation equipment at PS 1 and back-up generators at PS 9. (August 2004). Ex. ATC-279. Notably employees stated that the failure to secure a power agreement for PS 1 significantly impacted the engineering and procurement effort. Ex. SOA-7.

[376] SNC/Hinz were hired to perform preliminary engineering on April 28, 2003, and they released their report on November 3, 2003.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

648. A significant driver for the accelerated schedule was the avoidance of upgrades for fire protection.[377] Ex. SOA-60 at 24. "The project is operating on a tight schedule in order to meet fire system commitments . . . Delay of the project will result in . . . increased major maintenance costs (including fire and gas system upgrades). *Id.* The Carriers assumed that they would avoid upgrading their fire protection systems in at least 75 buildings by letting them go cold if they completed SR by the end of 2005.[378] Ex. SOA-60 at 9, SOA-108 at 1. This assumption was wrong. The assumption could have been validated by a simple review of compliance documents available at the time. The predicate for the Fire Marshall's requirement was the original construction of the buildings, they contained foam insulation in the wall panels. Ex. SOA-150 at 10. The Carriers in their brief still attempt to justify this assumption. Carriers IB 146. However, their assumption was contrary to a thirty year old agreement the Carriers had made with the authorities. Ex. SOA-104 at 2. The Carriers had been warned of this in the JPO December 2003 project review letter. Ex. ATC-233 at 14-15, 23-24. In December 2003 the fire and gas suppression issues had not been resolved. The JPO notified the Carriers that: "The SR Design criteria where only 20% of the walls [are] removed and the building goes cold would not require a fire protection system. Such a design does not meet State building code requirements." Ex. ATC-233 at 9. Thus the Carriers knew well before sanction that there were serious defects in their design assumptions. The Carriers had to spend $20 million dollars on fire and gas upgrades that they had not planned. Exs. SOA-292 at 3; SOA-542 at 57 (citing SOA-60 at 10 and SOA-150 at 8). Hisey testified as follows: "… I don't know how in the world you can underestimate the regulatory oversight. . . being the most regulated pipeline in the world." Tr. 3032:2-7.

649. A prudent pipeline manager would ensure that project contractors, managers and planners were fully aware of any and all federal, state and local regulatory requirements including permitting, fire and gas requirements, and other filing mandates.[379] As Sanders stated:

> [n]either the SR Project Team nor SNC did adequate study of the regulatory requirements, including an inexplicable failure to determine the design requirements to comply with fire and gas regulations. Even though a primary economic justification for the project was based on completion by

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[377] Other drivers were tax savings by December 31, 2005 and realizing organizational savings as fast as possible. *Id.* The impact of a one year delay was estimated at$90 to $100 million.

[378] This was one of the drivers for fast-tracking the schedule. Carriers IB 138.

[379] Sanders testified that from a regulatory standpoint there was a tremendous amount of information that was missing that would normally be done in a FEED." Tr. 1278-81:23-3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> the end of 2005 – to avoid having to do fire and gas upgrades – the TAPS Carriers didn't even pursue approval of a detailed basis of design for the Fire and Gas System Upgrades with the Fire Marshall before sanction.

Ex. SOA-542 at 55-56.

650. The State is correct that the impact of this is significant. State IB 164. First, the projected savings from not having to upgrade the fire protection systems was one of the drivers for completing the project by 2005 and the unreasonable preliminary engineering. Second, it caused the Carriers to create an incorrect design and redesigned that impacted the schedule and created rework problems. Third, the failure to properly analyze this design element caused the economic justification (comparison to Hybrid) to skew in favor of electrification. The State in its RB asserts that the costs associated with replacing or upgrading the fire code equipment were *de minimis* in comparison to the cost of the SR project. Moreover, repair or replacement were options available to remedy the fire and gas compliance issues and in 2001 it had been estimated repairs would cost $2 to $2.5 million. Ex. SOA-149. The State is correct that fast-tracking SR was not necessary to satisfy code violations and could not provide economic justification for fast tracking a multi-hundred million dollar project. State RB 29. The State is correct that at the time of sanction the engineering plans were so inadequate the Carriers did not know the extent to which buildings could be taken out of service and avoid fire and gas upgrades.[380] Hisey testified that there wasn't a lot of work done around everything else, the structural, cabling, fire marshal issues. Tr. 3279:20-23. Thus, it is concluded that the Carriers knew that the project scope was not clear at sanction. Exs. SOA542 at 54:13-55:2; ATC-278 at 66.

651. The Carriers knew the schedule was tight[381] and that preliminary engineering had been done in six months. Consequently, they should have known that project design was incomplete and inadequate. For instance, the lack of power supply contracts should have raised questions about whether the expected savings would materialize. In December 2003, the JPO noted that the schedule is highly aggressive and optimistic. According to the JPO this meant that major milestones should be considered to have a large measure of uncertainty. Ex. ATC-233 at 4. Thus, the Carriers were on notice that the schedule was

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[380] Howitt testified that "at the time of the AFE SO20 submission, the retained buildings decision had not been finalized." Ex. ATC-19 at 98:1-2. Further, he testified that because of "the interdependencies of the systems in the buildings the determination of which buildings would remain didn't occur until later in the preliminary engineering effort." Ex. SOA-163 at 6.

[381] Ex. SOA-474.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

not reasonable.[382] As F. Adams testified, the schedule did not have sufficient "resource loading." Ex. SOA-275 at 118. "While some of the engineering activities do contain some resource information, the vast majority of the remaining procurement, construction, and start-up activities did not contain resource-loading information at sanction. *Id.* The JPO also notified the Carriers that "the program schedule must coherently pull together all key elements that must be done. (Elements now strewn throughout the document)." Ex. ATC-233 at 4.[383]

652. The State asserts that a key deliverable of preliminary engineering is a cost estimate of +/- 15% but this was not achieved. The State is correct. As evidenced by the Carriers own exhibits, as of October 2003 there were notable deficiencies … in the operating and maintenance savings element of the project justification … project costs. Ex. SOA-475. Cost and savings sensitivities to project scope and timing were not specified and were probability based. *Id.* at 3. In addition, no evidence was provided to support the "conservative nature" of the project's cost estimates. *Id.* For instance, evidence in the record shows that DeHaas requested backup for the cost estimates from SNC and did not get a satisfactory answer. This prompted DeHaas to question the details and what they were doing. Ex. SOA-284 at 2. The State contends that the reasons the details were not available is that the Carriers did not perform the preliminary engineering that was required to substantiate the costs of the project. The State is correct.

653. Sanders testimony in this regard is given significant weight. He testified that the development of the Electrification design at the time of sanction, when preliminary

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[382] The SR Team called the schedule aggressive, no float, it had to be flawlessly executed, "a lot of terms that are scary around a big project in the most highly regulated pipeline in the United States, in Alaska, in Artic conditions, a mega project, at the time conceived to be $250 million." Tr. 3023:3-11. *See also* Tr. 3445:7-17; 3648:10-3650:13, 3023:3-11.

[383] Sanders' testimony lists a number of deficiencies noted by the JPO. Ex. SOA-542 at 71:8-73:11. "Within the 34 pages of issues cited by the JPO, there was a recurring theme that the Electrification design had numerous errors in codes used and interpretations of code intent. These failures to understand applicable codes later led to major issues that caused major engineering changes in drawings and specifications-including purchased equipment and fabrication details. Code errors included references to wrong building design codes, Canadian standards rather than applicable US standards, spacing errors and omissions for layout, and other issues that should have been viewed as a major red flag just prior to intended sanction." *Id.* at 73:4-11. "This indicates that engineering was not sufficiently complete. *Id.* at 73:14. As discussed below, in 2005 at the AFE SO20 Supplement 2, a lot of these deficiencies were cited by the Carriers as significant cost drivers and reasons for delays.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

engineering was supposed to have been completed was far below the +/- 15% cost estimate contrary to what the Alyeska procedures manual required.

> Logically, understanding what work you are going to perform is necessary to allow one to estimate the cost of the work. It is readily apparent that the TAPS Carriers understanding of the scope of the work for Electrification was far below the level necessary to support a +/- 15% estimate.
>
> For example, the TAPS Carriers originally estimated that 30% of the work would be on existing facilities (Brownfield) and that 70% of the work would be on new facilities (Greenfield). It turned out, however that the actual scope of the work was the opposite – 70% Brownfield and 30% Greenfield. Exhibit No. SOA-458 at 1. The estimate was exactly backwards. Put differently, the TAPS Carriers based their estimates on a design that was so ill-defined that they did not have an accurate understanding of how much work was to be performed on a new facility or an old facility, and the estimate was so far off that they had to do more than twice the work (on a proportional basis) they thought they would have to do on pre-existing facilities.

Ex. SOA-542 at 54:11-55:2.

654. The Carriers own documents show that they were warned of the risks of inadequate engineering. The AFE SO20 for $7 million to fund preliminary engineering stated that costs can escalate based on several factors.

> Accuracy is limited at the front-end of a project and costs can increase as scope if [sic] better defined. Also as indicated above, demand for equipment and services can place upward pressure on costs. Sufficient engineering needs to be completed to minimize “scope creep”, changes, and re-work. Contracting strategies need to be creative to obtain the best prices. And, peer reviews with Owner companies should be utilized to ensure best practices.

Ex. SOA-59 at 6-7.

655. Concerning savings the document points out that improper planning can promise undeliverable savings. “The savings must be achievable. To develop confidence in the predicted savings, a complete post-electrification plan needs to be developed. This will include written plans for operations, maintenance, spill response, and the support groups. Resource requirements will be considered and organization charts will be drafted. Each department manager will need to “buy-in” to the plan and remain committed to the end result.” Ex. SOA-59 at 6-7. The Carriers did not follow these directives and proceeded to sanction with inadequate preliminary engineering. As D. Hisey testified, a

20140227-3052 FERC PDF (Unofficial) 02/27/2014

"reasonable, prudent manager would take those [risks] into account and know that you are going forward at your own peril of cost overruns and schedule." Tr. 3849:15-17. The risks identified in the document happened: scope was not adequately defined, costs increased dramatically, and promised savings were undeliverable.

656. The Carriers viewed the project as a greenfield project, in which a new electrical motor,[384] drive and pump would be placed in a module, the module brought to the site, and then be plugged into the existing facilities.[385] Tr. 3024:2-25; 3029;9-3030:1; 3065:18-3066:7; 3066:22-24; 3279:14-20. The project turned out to be a much more complicated brownfield project, in which most of the work and costs occurred outside of the module. The module had to be integrated with existing buildings such as support facilities, warehouses, and shops. New control systems had to be installed. The communications systems had to be changed out. A new control and communications center had to be constructed. Pilings had to be installed and new pipe run. The oil spill response plan had to be revised. Electrical code, cabling, and Fire Marshall issues had to be addressed. The Alyeska procedures for documentation, tagging and records had to be followed. All of this took place while the pipeline was operating. Tr. 3024:6-15; 3031:10-18; 3035:18-3036:10; 3065:24-3066:7; 3066:24-3067:8; 3279:20-3280:1; 3923:15-3924:14; 3926:3-3927:11.

657. The SR modules were not "self-sufficient" since extensive tie-in work needed to be performed in the field. Ex. SOA-308 at 2. Further, the amount of wiring and cabling

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[384] The concept was that off the shelf technology would be used. Tr. 3067:13-16; 3440:6-14; 3444:2-7. However, these electric motors had never been built before, the design had never been used before, the MLU train had not been built before. The motors were serial number 1 motors. Tr. 3067:16-20; 3434:15-3435:8; 4026:14-4028:3. Both the motors and the modules had to be redesigned. Tr. 3441:12-21; 3442:23-3443:5; 4028-4-19. As of February 2005, they were still experiencing problems with the motors. Tr. 4025:20-4026:13. At one point, consideration was given to changing companies. Tr. 3442:23-3443-5. These motor problems led to delays in the project. Tr. 3446:16-19.

[385] This assumption was used to justify not updating the legacy equipment as impractical because of the brownfield nature of the work. Dr. Boyce challenged this, stating that, control systems are routinely upgraded on major pumping stations around the world. "The legacy system can be easily upgraded. Ex. SOA-543 at 47. "The legacy system is based on PLC's" (Programmable Logic Controllers) "which have ladder logic which controls the turbine pump packages. To upgrade the control systems, new PLCs would be needed and an upgrade of the OCC computers to which they are connected. In this case, the Brownfield nature of the work would greatly reduce the cost of the upgrade of the control system from the cost of a Greenfield system. This is because the most expensive part of any control system is the instrumentation and the hard wiring of the controls to the PLCs." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

was much more than anticipated. *Id.* These conclusions were later confirmed in a supplemental request for funding. Ex. SOA-218 at 4. "Significant increases in the quantity of pipe rack and cable tray support structural steel, and electric cables have occurred during the detail design development. These design development issues are not considered to be scope changes, but have significantly contributed to the overall cost increase." Ex. SOA-65 at 12. This again is evidence that the Carriers failed to determine the scope of the project, which resulted in increased costs. There is no evidence in this record showing that they went back and estimated the economics of the project based on these issues. Anadarko argues that the economics no longer supported the decision to complete the project. Again the record does not support such a finding since the economics were never revisited in a correct fashion at this particular point in time. Further, the Carriers did not stop or delay the project to finish the engineering so they could determine both the scope and the costs.

658. The Carriers attempt to blame the major breakdowns in the project schedule and increased costs on an "unforeseen" increase in brownfield work. Carriers IB 146-47, 173. However, the fundamental error in quantification of the brownfield work was only unforeseen by the Carriers because they had not done adequate preliminary engineering and FEL. The Carriers should have known that the project was predominantly Brownfield. It defies all logic to think otherwise and a reasonable utility manager would not have concluded that the work was predominantly Greenfield in good faith, under the same circumstances and at the relevant point in time. Further, and at a minimum, the assumption should have been validated during preliminary engineering as reasonable engineering practice requires. The fact that it was not, shows that the Carriers did not act in a reasonable manner and thus were imprudent. If the Carriers had not ignored the input of Alyeska employees who ran the day-to-day operations of TAPS, they would have known this assumption was invalid. The Carriers admit that they failed to identify the basic nature of the work (brownfield v. greenfield) during pre-sanction engineering. This is an admission that inadequate engineering was performed prior to sanction and prior to starting execution.

659. The State correctly argues that the problems associated with the rushed preliminary engineering were exacerbated by the selection of an inexperienced SR Project Management Team and a contractor who had never worked on TAPS or with Alyeska. State IB 160. SNC Lavalin the primary engineering contractor, selected to do the preliminary engineering work, had no previous Alaska or Alyeska experience.[386] Ex. SOA-275 at 143:20. SNC focused on the design for the electrification of the pump stations. Hinz Automation (Hinz) focused on the design for the automation and security of all the pump stations. JTG assisted Hinz with engineering for the control systems. Ex. SOA-1 at 152.

[386] SNC was hired to perform Engineering, Procurement and Construction Management. Ex. SOA-275 at 142:15-19.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

660. SNC was based out of Edmonton, Canada, and had no experience of US standards, or Alaska standards or practices, and did not have any track record of work in artic conditions. They were not familiar with Alaskan codes and regulations. Hisey testified that SNC only had one licensed electrical engineer to review the drawings and designs for a project that involved electrification. Tr. 3259:2-8. The Carriers knew of SNC's lack of experience at the selection phase and their claim that complaints about SNC and Hinz selection is based on hindsight is without merit.[387] For instance, comments at the selection stage state that SNC "proposed lead has no pipeline experience. Other team members are okay, but light on hours. Poor understanding of scope." SNC was rated the lowest with respect to Alaskan experience. Ex. SOA-217.

661. State witness C. Sullivan testified that the SR PMT's selection process was flawed because it did not properly emphasize Alaskan experience. Tr. 2186:14-23. Sanders also testified that the Carriers acted unreasonably when they retained SNC because they should have picked a contractor with more Alaska experience. Tr. 1855:3-16; 1868:2-11. This testimony is given significant weight.

662. The Carriers argue that the selection process was adequate. Carriers IB 152-53. The process started in April 2003, solicited bids from contractors with experience in "project management/estimating for projects in the $50 to $200 million range. Carriers IB 40; *see* also Ex. ATC-25 at 4:14-19. However, the PMT informed the Carriers back in November 2002 that the SR project was going to cost at least $234 million. Ex. ATC-158 at 8. The contractor selection process solicited bids using the wrong qualifications. The Carriers also argue that protestants misquote the evidence citing Exs. SOA-217 and ATC-182 arguing that SOA-217 is for controls and not for electrification. The selection criteria for SNC for electrification in Ex. ATC-182 ranks SNC lowest in arctic design, next to the lowest in seismic design and lowest in modular facilities design. Ex. ATC-182 at 4. This exhibit also states that the SNC "team is forming, not mature." *Id.* at 5. Nothing in either exhibit gives SNC any arctic experience. The Carriers argue that in order to comply with US electrical standards SNC had one engineer out in Redmond, Washington, who will "undertake reviews of all electrical packages." This engineer was a licensed electrical engineer in the State of Alaska. It defies logic that in a project as big as SR one engineer was sufficient to review all the engineering packages. This is not the action of a reasonable utility manager.

663. Moreover, once selected they did not give the contractor time to obtain necessary knowledge of TAPS or Alaska and they were not adequately supervised. Sanders' testimony in this regard is given significant weight. He testified that if the Carriers were going to hire a contractor without substantial local experience and knowledge of local regulatory requirements, "a reasonable pipeline manager would ensure that there was a

[387] Carriers IB 160-61.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

team of sufficiently qualified personnel and project management embedded within SNC from the beginning of the project (rather than only when problems started to arise) that actually provided detailed supervision of the contractor (rather than just occasional support)." Ex. SOA-542 at 83:19-22. Barrett testified that the Carriers and their affiliates are large international companies that have extensive operations in Canada and should have known at the time of sanction what the differences were between the engineering product of a Canadian engineering firm and that of an American engineering firm. Tr. 5839:12-5840:4.

664. The Carriers admitted that the SR PMT in place during preliminary engineering was not the "experienced Owner project 'A' team. Ex. SOA-381 at 12. They had no experience with TAPS, or similar pump station projects, and no experience working with Alyeska. Sanders also testified that a reasonable pipeline manager would have ensured that "the project management team should consist of appropriate, qualified personnel. This should include competent and experienced staff to evaluate cost estimates and project progress as the project develops." Ex. SOA-425 at 86:4-8. The Carriers did not do this.

665. The Carriers set up the SR PMT as a structure separate and parallel to Alyeska. Ex. AT-230 at 16:3-11; Tr. 3295:25-3296:14; 3357:19-3358:7; 3392:22-3393:1-5. The PMT was in charge of designing and executing the project. Tr. 3356:9-3357:2. The PMT staff were Carrier or affiliate employees. Ex. AT-230 at 16:3-11; Tr. 3295:25-3296:11; 3853:16-3854:5. J. Barrett (the PMT Manager) reported to the Alyeska President, D. Wight a BP employee.[388]

666. M. Yaege confirmed that the separate structure was employed to "blast through" Alyeska's red tape and deliver a lower cost project." Ex. SOA-172. D. Hisey testified that there were various reasons the Owners set up an independent management team.

> One was Alyeska seems a high cost operator. The owners believe that Alyeska's systems are complicated, procedures are complicated, bureaucratic, if you will, that we were slow, that we were, you know, too focused, that they needed to speed it up. So they described what they wanted to introduce was break-through thinking, and break-through thinking would be brought into Alyeska with a contractor from outside that hadn't worked for us before who was going to show Alyeska how to do the work, and they were going to show us how to build a pump station and how to change out the control system and do it cheaper than we ever imagined.

Tr. 3025:18-3026:7.

[388] Tr. 3295:25-3296:11; 3853:16-3854:5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

This decision which led to ignoring the input from experienced Alyeska employees is not how a reasonable utility manager would behave.

667. Larkspur in December 2003, noted that "[e]scalation, contingency and Owner costs are not included in the estimate and will be added by the Owner." Ex. SOA-222 at 3. Larkspur did not agree with the cost estimates or that the accuracy range was in the 15%. Ex. SOA-222 at 3. Larkspur concluded that it had "major concerns that the project as currently designed could be built for the current estimate value." *Id.* at 13. Sanders testified that a reasonable pipeline manager would not sanction a project until "they have reached a level of engineering detail that actually defined costs within +/-15%." Ex. SOA-542 at 62:12-15. Sanders testified that as of the end of 2003, "the level of engineering study was insufficient in key areas and the economic analysis was deeply flawed. Therefore, a reasonable manager would not have progressed to sanction." Ex. SOA-542 at 68. He also asserted that if the sanction decision is made prior to this then scope, costs and schedule would be ill defined. *Id.* at 62:16-18. However, as discussed below the Carriers apparently relieved Larkspur of its contract and disregarded Larkspur's warnings.[389] This totally contradicts the Carriers arguments that the process followed during preliminary engineering was reasonable, and that multiple "cold-eyes" or peer reviews were conducted by the Owners' subject matter experts, the contractors, and outside consultants IPA and Larkspur. Carriers IB 132.

668. Similarly, in November 2003 IPA concluded that the "status of the project definition, or Front-End Loading (FEL), is currently in the Poor range." Ex. SOA-287 at 3. This is indicative of projects that "have much more variable cost and schedule results." *Id.* However, the Carrier's reaction was to have them come back and do an update. "If we send this to the Owners, we will be explaining it forever." Ex. SOA-489. Thus, IPA's warnings were ignored. IPA also indicated that the PMT has "not yet looked into potential problems it might face during execution. The team could benefit from a brainstorming session on the difficulties the SR Project might face in execution. After the identification of problem areas and potential risks, the team should develop mitigation strategies to handle the problems in case they occur." Ex. SOA-287 at 4. This was four months prior to sanction and the PMT had not analyzed the problems with implementing this change to TAPS. Tudor (Exxon) was aware of the poor rating of the IPA report. Tr. 4989. Yaege testified that Conoco did not have employees with the skills to review the details of the project. Tr. 4767:5-24. IPA also provided a disclaimer that "any scope changes to the project may alter or invalidate the analysis results discussed in this report." Ex. SOA-287 at 2.

669. The lack of development of the Hybrid and Inertia alternatives also represented a departure from established industry standards. This lack of work made the savings numbers for electrification suspect. Exxon's President in November 2003, asserted that

[389] Ex. SOA-308.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

one of his "many issues" with the preliminary engineering work was the "apparent abandonment of the 'do nothing' or 'hybrid' case from a development perspective that seems to make it impossible to accurately compare the proposed project versus the next-best alternative. Ex. SOA-183.

670. Sanders testified that a "reasonable pipeline manager would not take the financial and operational risks of a complete replacement of all existing, well-functioning equipment lightly." He continued that "if smaller-scale modifications to the existing equipment could provide most of the sought after O&M benefits of replacement, at lower costs and risk, the reasonable pipeline manager would not perform a full replacement." Ex. SOA-542 at 37. As Staff avers, in three months, on the basis of two Power Point presentations and without any risk analysis, the Carriers abandoned the existing pumping system as the base case in favor or electrification. *See* Exs. ATC-138 at 6, 47, 49; SOA-451 at 3.

671. The State and Anadarko are correct that the preliminary engineering process was completed improperly, in too short a time frame, with a work sequence that was not correct and with significant and notable deficiencies in several areas. As will be described later on, even the Carriers agreed with the assessment that preliminary engineering was completed improperly.[390] Ex. SOA-219. The Carriers noted significant and notable deficiencies for this stage in several areas on October 28-29, 2003. Ex. SOA-475. Moreover, the Carriers themselves admitted that the project was only at the "conceptual engineering" level at the time of sanction. Ex. SOA-308. Therefore, it is found that the Carriers failure to properly complete sufficient FEL and appropriate preliminary engineering was contrary to industry standards and not the actions of a reasonable utility manager and are thus imprudent. As Staff argues, the Carriers failure to complete design work prior to sanction was so fundamental a breach of good project management practice that an audit characterized electrification as being at a "conceptual engineering" level at sanction. Ex. SOA-308.

672. The conceptual level assumptions persisted during preliminary engineering even as scope and cost growth changed. Exxon personnel expressed concern in July 2003, that the "scope is forever changing." Ex. SOA-453 at 1-2. Others complained about increasing project costs for instance in October 2003, D. Ahrens complained that "the Hinz estimate for the equivalent scope has increased from $37M (10/9) to $49M (10/20) to $57M (10/24), and I think we need to address the increase now, as opposed to waiting until we submit the sanction AFE. Anybody got any heartburn?" Ex. SOA-220. M. Tudor, in November 2003, noted "there are many issues" with the project "the obvious significant scope and cost growth from Gate 2 to Gate 3, as yet not fully explained and

[390] The findings included that the "conceptual SR program estimate set a benchmark that negatively influenced future project decision making and execution approach. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

reconciled." Ex. SOA-183. Hinz' cost increases (almost 60 percent) were ignored by the Carriers.

673. The December 2003 economic analysis (AFE S020) repeated and magnified the preliminary engineering flaws.[391] It failed to take into account the risks to the schedule and reduced contingencies. It was an underdeveloped, unsubstantiated cost estimate based on inadequate preliminary engineering. Additionally, it relied on unsupported staff savings and major maintenance savings that had been rejected in their own documents. The State is correct that this failed to follow reasonable industry practices. If reasonable industry practices had been followed AFE SO20 would not have been submitted until all of the expert critiques were addressed and reasonable preliminary engineering work had been completed. The original SR cost estimate of $250M was not sufficiently validated and was based on figures that were really conceptual engineering and not preliminary engineering. See below, findings 2007. As D. Hisey testified, the "schedule was impossible. And because they had that schedule, they didn't have adequate engineering to get a good estimate. And they didn't get a good cost estimate because they didn't have a full scope of work." Tr. 3023:23-3024:1. The cost estimates were based upon a number of flawed assumptions developed during conceptual engineering and not tested during preliminary engineering. For instance, AFE S020 cost estimates continued to assume, that complete modularized construction would be available without much brownfield work,[392] that 75 buildings could go cold without required fire upgrades,[393] that third party power generation would be available at PS1 and PS9,[394] and that the project could be completed by 2005. As Staff correctly asserts, AFE SO20 was inaccurate, understated the costs of electrification, and overstated the savings of electrification relative to hybrid. Staff RB 31.

674. The State is correct that the staff savings estimates in AFE SO20 were unsupported. The total staff savings for electrification 285 personnel reductions (excluding reductions at PS 5 and 7)[395] was not substantiated nor was it distinguished from other options, i.e. why those savings could not be achieved under Hybrid. Moreover, the prior studies (1994-2001) showed that similar staff savings could be achieved with the automation of legacy equipment. For example, the May 2000 AFE F180 support package concluded that a system using the existing equipment optimally could provide fully automated pump stations as well as a flexible and non-stationary

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[391] This included the Electrification vs. Hybrid Decision Document, Ex. SOA-28.

[392] Ex. SOA-60 at 2.

[393] *Id.* at 5-7.

[394] *Id.*

[395] Ex. SOA-60 at 15.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

maintenance team" for staff savings of 265 persons. Ex. SOA-153 at 7; 11; 17; and 23. The State avers that technological advances in computer, remote operation and automation since the original studies were done would most likely increase these staff savings. State IB 183. Pomeroy testified that technological advances in computers, internet and speed of communication are allowing advances in real-time data sharing. Tr. 7899:20-25.

675. Moreover, Anadarko and the State are correct that the Carriers could have achieved regional oil spill response, regionalized maintenance and automation for unmanned operations with the legacy equipment and obtained the same personnel savings (hybrid would have achieved the same staff savings). Ex. ATC-117 at 5; 6 and 16. *See* Findings for 2004 and 2005 below, supporting the findings that the Carriers own documents demonstrate that the staff savings were solely attributable to automation. As a matter of fact, Hisey testified that the reliability, safety, and maintenance concerns with the untested and complex electrified pump stations would suggest fewer operators but more maintenance personnel at the electrified pump stations. Ex. AT-405 at 8-9.

676. As Anadarko points out the chief operating officer for Alyeska (D. Hisey) confirmed that the staffing levels at the PSs are driven by staffing strategy (degree of regionalization of maintenance and spill response), the degree of automation and pipeline events. Ex. AT-405 at 6. In other words, staffing levels are not driven by whether the MLUs are electrified. The pump stations were designed originally to operate with minimal staffing, but were staffed with additional personnel for decades for reasons not related to electrification. Ex. SOA-572 at 13 n. 22. Pivett (a senior member of Alyeska's technical staff) at his deposition testified that staffing changes are not attributable to electrification of the MLUs. Ex. AT-431 at 21.

677. Additionally, one of the drivers for the project, was personnel savings, which as established above, are derived from automation. However, the scope of automation was not well defined as late as October 2003. For instance, the October 2003 Owner Project review concluded that the gap "in development of Automation scope and execution plan" was so large that it characterized the automation portion of the SR Project as being "based on a vision, not an established plan." Ex. SOA-475 at 8.

678. The State argues that the AFE S020 maintenance savings estimate was unsupported.[396] It included tens of millions of dollars in major maintenance estimates for Hybrid and Inertia but zero for electrification. The State maintains there is no support for the assumption that no major maintenance would have to be done on the new equipment during the 20 year planning window. It further asserts that based on the Carriers

[396] Tr. 6981:5-10 (repairs to turbines are not considered major maintenance but O&M). The savings in maintenance expenses were estimated to be $384 million over a 20 year planning horizon. Ex. SOA-60 at 9; 17.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

experience operating the new Siemens turbines, this was indeed an unrealistic assumption. The estimates were not reviewed by a third-party. Tr. 7309-13-22. J. DeHaas expressed his opinion that the new pumps would not be as robust and reliable as the legacy units and would not be any better. Ex. SOA-19. Carrier witness J. Johnson testified in his deposition that he did not agree with the zero maintenance figure. Ex. SOA-727 at 2. DeHaas believed that the new equipment might require more maintenance than the legacy equipment. Ex. SOA-19. He also believed that the maintenance costs of new machines would be higher. *Id.* at 2.

679. The methodology for estimating future major maintenance was primarily a numeric exercise with little in-depth analysis of future operations. In the Pipeline Reconfiguration Economic Evaluation Report dated December 2003, (Ex. SOA-13) the estimates were explained. The Carriers knew that the estimate for major maintenance savings were based upon estimated savings for 10 years through 2013. Ex. SOA-13 at 7. For year 2014 and beyond they used an average of 2004 to 2013 savings. *Id.* at 9. Anadarko correctly argues that the savings for half of the planning period are not supported by any detailed analysis of future operations. In addition, the State argues that the maintenance estimates for Hybrid and Inertia were further escalated by adding a multiplier arbitrarily (10% in year 2 and 30% in year 3 and 50% for each year thereafter. Ex. SOA-13 at 9. This was a provision for unanticipated major maintenance costs. *Id.* These figures are not supported. At hearing Dr. Toof corroborated the fact that this would advantage electrification. Tr. 7481:7-19.

680. Sanders testified that "it is important to evaluate the options based on a sufficient level of engineering detail because without sufficiently detailed studies, the cost of each of the options could not be fairly assessed. Ex. SOA-542 at 47:16-18. He further stated that Alyeska engineering personnel refuted the maintenance savings for electrification citing Ex. SOA-21. Ex. SOA-542 at 48:12. This testimony is given significant weight. The State is correct that there were insufficiently detailed studies and the numbers were biased in favor of electrification and inflation of estimated major maintenance costs for Hybrid partly due to the application of an unsubstantiated major maintenance multiplier. It is found that the State is correct that the unsupported maintenance savings, together with the unsupported staff savings projections and the unrealistic construction cost estimates, misrepresented the economic viability of electrification. As Staff points out, the manner in which these estimates were developed should have indicated to the Carriers that the sanction process should be stopped until reasonable estimates were developed since over $50 million were not based upon any specific estimate of actual major maintenance tasks that would have been required in the future. Staff RB 31.

681. Anadarko argues that as a result, the Carriers were aware that (1) no specific project-by-project analysis was attempted for half of the planning period; (2) every year during the planning period included "unanticipated major maintenance" costs; and (3) "unanticipated major maintenance" costs were artificially increased by 50 percent each year after year three. Howitt testified that if a mistake or incorrect assumption was made,

20140227-3052 FERC PDF (Unofficial) 02/27/2014

it would be magnified over the 20-year planning horizon due to the multiplication of the factors. Tr. 4455:21-4456:8. Additionally, Howitt testified that they calculated "a 10 year number and double[d]it" or extrapolated it out. Tr. 6979:11-15; 6977:22-24. Anadarko is correct that this "extrapolate" process makes $100,000 of savings in a year into a 20 year total of $2.88 million. Tr. 6984:5-7. Howitt also testified that the 10-year base period included a significant percentage of "what happened that wasn't expected in the past," thus "calling avoided major maintenance" an estimate that is "based on what you don't know instead of what you do know." Tr. 4506:3-19. There was no third party review of these estimates. Tr. 7309:13-22.

682. Anadarko is correct that the estimate of major maintenance savings provided no meaningful estimate upon which to base an economic decision. Thus, it is concluded that these estimates are not valid and a reasonable utility manager should not have relied upon them to make a decision to proceed with this project. Howitt confirmed that some significant items of savings never materialized because buildings, a sewer system, and an airport remained in service. Tr. 6989:8-6992:24. Thus it is concluded that the maintenance savings were overstated. The methodology was a numeric exercise that could transform savings of $100,000 a year into a 20-year total of $2.88 million. Tr. 6984:5-7. Anadarko is correct that the methodology resulted in a 44% overstatement of the estimate. Accordingly, as Anadarko points out,[397] the estimate of major maintenance savings provided no meaningful estimate upon which to base an economic decision. As discussed below maintenance costs have not decreased and are projected to increase in the future.

683. As Anadarko states, major maintenance expenses are also not driven by whether the MLUs are electrified. Anadarko IB 6. Automation, regional spill response and maintenance all, could have been done without electrification of the pump drivers. In fact in the Electrification vs. Hybrid Decision document there is a statement that the "major mechanical equipment is operating extremely well. Reliability is very high and unplanned shutdowns are rare. It is working so well that maintenance personnel are not retaining their skills such as changing mainline pump seals, etc." Ex. ATC-154 at 31. According to Anadarko the SR team's calculation of major maintenance reduction reflects more the bias of their approach than it does the likelihood of a reduction. The record in this case shows that the major maintenance levels are driven by the budgeting process and are increasing. The Carriers completely failed to meet their burden to demonstrate that major maintenance has been reduced due to the electrification of the MLUs.

684. Staff points out that W. Howitt admitted that the "unidentified major maintenance multiplier" was developed by merely reviewing all line wide unanticipated major maintenance in the past and then coming up with an arbitrary percentage to apply to the

[397] Anadarko RB 67.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

maintenance amounts for an "unidentified component going forward." *See*. Ex. ATC-19; Tr. 4453-4460.

685. Even the wording of AFE S020 does not support the proposition that electrification would "reduce future major maintenance expense." Carriers IB 11. The document itself states that it will "also reduce future major maintenance exposure." Ex. ATC-237 at 13. Carrier witness Ray testified that additional cost savings would be achieved in the form of avoided major maintenance expenses. He argued that the legacy equipment would have to be overhauled or refurbished on a regular basis. "Some of this would have been due to the age of the facilities; some would have been due to the continuing reductions in throughput; and some would have been due to regulatory requirements." Ex. ATC-18 at 6:18-23. He also testified that at sanction the estimated cost savings were approximately $1.1 billion which included annual operations and maintenance cost savings of approximately $41 million, most of which resulted from reduced staffing." *Id.* at 7:5-8. First, it is noted that Ray testified that most of the savings resulted from staffing and not from equipment maintenance. Second, it is noted that the record is devoid of any comparison of maintenance expenses of the new equipment. Thus, it is found that the maintenance "expense" savings are not proved on this record.

686. The project was driven by savings from de-manning the pump stations and letting the buildings go cold. The Carriers relied upon estimates done by Johnson and his team in 2002. Witness Howitt testified that the Carriers did not have a third-party review these estimates. Tr. 7309:13-22. First, there is no support for the figures developed by Johnson. Moreover, Johnson testified that he did not rely on Bailey or Kenonics to develop his hybrid staffing numbers. Tr. 8185:13—8186:2; 8187:8-17. Additionally, Johnson testified that he and his team did not have experience with automation. Tr. 8157:8-12; 8206:5-8208:20. Nor did they consult with experts on automated control systems or predictive maintenance systems. Tr. 8206:5-8208:20. Further, Johnson or his team did not consult with any of the manufacturers of automation systems to determine the systems capabilities. Tr. 8232:23-8233:1. In addition, they did not consult with anyone with experience using modern automation systems. Tr. 8232:17-20. Johnson also testified that it took him seven weeks to complete[398] his analysis on a part-time basis since his primary responsibility was operating the pipeline. Tr. 8258:5-12. He spent about one-third of his time on the analysis for the SR project. Tr. 8261:18-23. Johnson did not know what ancillary equipment was needed to run the turbines, VFDs, and generators. Tr. 8219:8-11. In addition, he did not see any detailed engineering documents of any of the SR mainline units prior to doing his staffing analysis. Tr. 8302:9-14. Thus, Johnson and his team did not do a "reliability centered maintenance process" in order to determine the estimate of future maintenance required after SR. Tr. 8302:15-22. Johnson admitted he had only rudimentary understanding of predictive maintenance. Ex. SOA-689 at 7. Nor did he know the details of the devices that were to be added to existing equipment to automate TAPS. Ex. SOA-743 at 3.

[398] Tr. 8245:10-13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

687. Johnson admitted he "staffed to a concept." Tr. 8303:19-22. He was shown documents and photographs that assumed a "good share of the buildings would go out of service with electrification." Tr. 8209:5-7. Johnson knew that maintenance work was "on all of the subsystems and utility system that are needed to support that system." Tr. 8452:18-20. So he concluded that if the buildings and systems were to be eliminated, then the maintenance work would decrease and with it the need for staffing. Tr. 8515:7-21. As Anadarko points out due diligence would have established that this analysis was based on incorrect assumptions of buildings and infrastructure being replaced by truckable prewired modules that would be fully automated. Johnson's staffing analysis, as stated above, is not given any weight in this decision.

688. The Carriers anticipated $899 million in savings over a 20 year planning horizon, in O&M expenses. Ex. SOA-60 at 9. In addition, they anticipated that 75 buildings would become non-operational, and an additional 27 would be declassified and /or Therminol system removed. *Id.* The O&M savings were based upon "reducing the number of facilities" to reduce facility maintenance and operations staff levels. *Id.* at 14. Anadarko is correct that the Carriers knew that the O&M savings were dependent upon the reduction in infrastructure and the assumption that the reconfigured infrastructure would require less maintenance and on-site operation. Anadarko is also correct that the evidence in this case shows that the Carriers did not independently confirm that these assumptions were valid and that they would result in the savings projected. Instead they relied on the numbers developed by Johnson in 2002. Pomeroy testified that there was no line item in the budget (estimate) for the cost of Alyeska operations staff that would be assisting with the project. Tr. 8021:18-23. This is contrary to the requirements of Section 6.1.4 of Alyeska's AFE Control Manual. Ex. SOA-30 at 54. Additionally, Anadarko is correct, that further study was warranted based upon the prior studies, such as the Bailey Report which concluded lower estimates of savings. For instance, in the Bailey Report, full automation was estimated to produce an annual pre-tax cost reduction of $26 million per year. Ex. SOA-135 at 27, Alternative F, line F. However, the estimate for electrification was almost $45 million of pre-tax cost reduction. There is no evidence in this record that there was ever any attempt to reconcile these numbers.

689. The Carriers did not question the numbers in AFE S020. As the State points out, this was significant since a late October Owner Review found a lack of evidence to support the cost estimates, "cost and savings sensitivities to project scope and timing" were not specified; and "probability based estimates and forecast, with supporting documentation" were not developed. Ex. SOA-475 at 3. This lack of independent review is not reasonable in light of the fact that this was a fast tracked project (less engineering than normal had been conducted), had already experienced significant scope growth "not fully explained and reconciled." Ex. SOA-183. Further, IPA and Larkspur had indicated significant flaws in the numbers. See findings for 2004 below.

690. At the February 20, 2003, Owners meeting the SR PMT warned the Carriers that the schedule was "aggressive with very little flexibility" with "zero float for three

20140227-3052 FERC PDF (Unofficial) 02/27/2014

years."[399] Ex. SOA-197 at 9. Additionally, they pointed out that the proposed schedule required "timely decisions and flawless execution."[400]

691. The State is correct that the Carriers should have known that a project as complex as SR could not be completed by 2005. As a matter of fact, for automation alone Bailey had predicted four years for completion. State witness C. Sullivan testified that if appropriate FEL and preliminary engineering had been done, a reasonable manager would have estimated 30 months for project execution.[401] Ex. SOA-1 at 181, Fig. 108. Even the Carriers own expert argued that 30 months was too short and did not include any allowance for unanticipated problems that often occur in a complex project such as this. Ex. ATC-34 at 11-12. Thus, this shows that even their own experts believe that the 2005 deadline was unrealistic.

692. Anadarko points out, the Carriers knew and ignored the impact on the project of establishing an impossible schedule. Anadarko cites to Merrow's[402] observation that "[s]chedule pressure dooms more megaprojects than any other single factor." Ex. AT-268 at 3. "That speed destroys megaprojects has been widely known within the IPA[403] customer community for many years." Ex. AT-267 at 2. Even Carrier witness Barrett admitted that at the time he took on the project, he was aware that "speed destroys

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[399] Zero float means that every element of the schedule has to be executed exactly to the schedule. In this case nothing could slip. If there were any slips the schedule was compromised. Tr. 3178:23-3179:16.

[400] Flawless execution means everything you plan to do has to go exactly as planned, you have no room for mistakes, and there's a lot of critical time dates. If a critical date slips, you miss one, and you have to look at the whole schedule and see if you can recover. Tr. 3180:4-11.

[401] C. Sullivan testified that fast-tracking a project "accelerates work relative to normal project execution." Ex. SOA-1 at 185. Typically, this requires that activities normally performed sequentially must be performed in parallel, or with a higher degree of schedule overlap. *Id.* A fast-track project faces "a higher risk of rework that results in schedule delays and increased costs." *Id.* This is well established in the construction industry. *Id.* at 186. As a result, the decision to fast-track a project should be subject to "careful consideration prior to sanction of the increased likelihood of budget overruns and schedule slippage." *Id.*

[402] Carrier witness Barrett admitted he did not read "Industrial Megaprojects: Concepts, Strategies and Practices for Success." Tr. 5665:22-24. However, he did confirm that the author, E. Merrow, "was the owner or founder of IPA." Tr. 5665:21.

[403] Independent Project Analysis.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

megaprojects." Tr. 5856:7-17. He also agreed that "fast tracking" (implementation prior to final design) causes significant risk. Tr. 5806:7-10. In addition, he confirmed that he explained the risks to the Carriers, these risks were significant, and that they assumed the risks. Tr. 5807:7-19.[404] Barrett said that at sanction he was "clear" with the Carriers that the Project had "zero float" and required "flawless execution." Tr. 5806:1-6. The schedule required "flawless execution" and "zero float" for three years. Ex. SOA-197 at 9. There was "no tolerance for delays" and required the Carriers to undertake a "non-typical funding strategy." Ex. SOA-232 at 7. The Carriers in this case decided to accelerate the project. It is found that this is not the action of a reasonable utility manager. Ex. SOA-232 at 7.

693. As Staff correctly points out, the decision to fast track the project was itself imprudent, a prudent manager knowing what they did at the time would not fast track the project. Staff RB 40. For instance, information from prior studies showed that a much longer schedule was necessary for a much less ambitious project (less expensive also). Studies from the 1990s showed that an automation and control systems project would cost $50-70 million and take four years. Ex. SOA-135 at 52 (approximately three years from start of preliminary engineering to project finish); SOA-134 at 31(approximately four years); Ex. ATC-108 at 38 (estimating approximately 3.5 years); Ex. SOA-153 at 12 (estimating approximately four years). The electrification project was more complex with a budget in the hundreds of millions of dollars. Moreover, the Carriers had been warned that the fast track schedule included "zero contingency" and provided "no tolerance for delays," and that meeting the schedule required "flawless execution." If the Carriers had followed standard industry operating procedures and determined the proper scope of the project (by doing adequate preliminary engineering and front end engineering design) they would not have "fast tracked" the project to achieve tax benefits and due to Fire Marshall mandates, as Staff correctly points out.

694. Evidence in this proceeding establishes that on April 2003, Hatley from Exxon discussed alternative funding plans with the other Carriers and concluded, "[i]t is likely that the Front End Loading Assessment would yield an unfavorable score, indicative of projects where the risk is high that either schedule and /or budget goals will not be achieved." Ex. SOA-173. Hatley explains that "IPA studies demonstrate that accelerating projects to meet earlier schedules so one can "start saving money soon' rarely pays out. Instead, what is typically seen is that project acceleration causes one to miss out on Value Improving Processes and … therefore [one is] forced to live with a

[404] The State argues in its reply brief at 38 that Carriers' witness Crider implicitly admitted that the electrification schedule was unreasonable when he criticized State witness C. Sullivan's proposed prudently managed schedule. Specifically, C. Sullivan's schedule was significantly longer than the SR schedule and yet Crider claimed that it did not "include any allowance for unanticipated problems that often occur in a complex project such as this." Ex. ATC-34 at 11-16.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

suboptimized project." *Id.* Thus, Hatley concludes that "there will be some who question the logic of project acceleration (both Conceptual and Alternative Plans) to achieve a 4Q2005 start-up." *Id.*

695. Other evidence shows that at least one Carrier, after reviewing the pre-2002 studies of electrification, noted that the entire project is probably a 3-5 year scope as it involves potentially redesigning and rebuilding all of Alyeska's Pump Stations. Ex. SOA-471. In a May 7, 2003, status report, the SR PMT warned the Carriers that the project schedule was "compressed . . . with [n]o tolerance for delays . . . [with a] need for flawless execution," and that "[s]chedule compression was causing gate review activities to converge." Ex. SOA-232 at 7. In July 2003, the Carriers were informed that the SR project was "difficult from a project management standpoint as the scope is forever changing" and that there were "a 'bazillion' balls in the air for operations in trying to sustain the core business functions while undertaking the most extensive change in the history of the company." Ex. SOA-453 at 1-2.

696. On December 2003, the JPO notified the Carriers that "[t]he schedule is highly aggressive and optimistic. This means that major milestones should be considered to have a large measure of uncertainty." Ex. ATC-233 at 4. The Carriers therefore, were on notice of the unreasonableness of the schedule.[405] Under these circumstances, the decision to accelerate the schedule is not a decision of a reasonable utility manager. Fast-tracking may be justified to meet regulatory requirements, minimize downtime, or for safety reasons.[406] However, none of these justifications applied to SR. There is no evidence in this record that the Carriers tried to analyze whether these justifications were even applicable to SR and whether they tried to quantify the higher risks they were accepting and whether the perceived benefits outweighed those risks before sanction. As a matter of fact, the evidence shows otherwise, Yaege asked what the cost of a longer schedule would be and SR Program Manager Barrett replied that it was hard to quantify. Ex. SOA-185 at 9. It is concluded that it was unreasonable and imprudent to fast-track the project without considering the risks and benefits of that decision.[407]

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[405] The schedule was tight. "They called it aggressive. They called it no float. They said it had to be flawlessly executed, a lot of terms that are scary around a big project in the most highly regulated pipeline in the United States, in Alaska, in Artic conditions, a mega project, at that time conceived to be $250 million." Tr. 3023:3-11. *See also* Tr. 3445:7-17; 3648:10-3650:13; 3940:11-14.

[406] Ex. SOA-186.

[407] The Carriers argue that fast tracking schedules is a common practice in the oil industry and cite the example of Kuwait oil pipeline infrastructure being rebuilt in 15 months after Dessert Storm on a super fast-track schedule. Carriers IB 139. The State answers that it is incongruous to analogize SR to a project needed to stop the environmental damage caused by oil flowing uncontrollably from war-damaged and

20140227-3052 FERC PDF (Unofficial) 02/27/2014

697. The evidence in this case also shows that there was no reason to fast-track the project. The legacy equipment operated at 99 percent reliability. Ex. SOA-263. The equipment was deemed robust and reliable by Alyeska experts. DeHaas, Alyeska's Senior Rotating Equipment Engineer believed the equipment was well-functioning and wrote that it was "stretching the situation to assume that all these projects have to be done within the next few years, . . . and use that as part of the premise and justification for installation of totally new equipment. A lot of this equipment can be maintained indefintitely…" Ex. SOA-21. He also stated, the pumps were reliable "and there is no reason they should not continue to be the same." Ex. SOA-25 at 95. GE also found the pumps were rugged and durable. Ex. ATC-147 at 22. The equipment was so reliable that Alyeska personnel believed that "many major components, such as on some of the gas turbine drivers, have preventative maintenance tasks performed on them solely for training purposes." Ex. SOA-23 at 33. As Sanders testified "there is no discussion in the evaluations of Electrification that identifies any engineering studies or any other substantive evaluation that would support the conclusion that the legacy equipment could not meet the TAPS Carrier's needs." Ex. SOA-542 at 19:15-17.

698. Cost overruns are directly related to the decision to fast track the project. Changing design and scope resulted in several re-estimates of construction costs. *See* Ex. SOA-257 below. By the time of AFE S020 Supplement 2, the costs of the project almost doubled as a result of inadequate scope definition at sanction. Ex. SOA-65 at 10, 12. These cost increases can be attributed to the decision to fast track the project and sanction it based on incomplete and preliminary engineering. Ex. SOA-166. As Anadarko correctly points out[408], in a project that is only being considered to save money in the future, it is essential that the regulated entity thoroughly define the scope of the project, accurately estimate the costs, conservatively estimate the future benefits, and adopt a resource-loaded schedule that minimizes the risk of a "train wreck."

699. Moreover, as the findings above show, preliminary engineering in this case was substandard. Consequently, the schedule should have been longer to account for the adequate completion of preliminary engineering. Proper engineering would have better defined the scope of the project. As D. Hisey testified, so "you are going into a process on an extremely fast cycle, and you know there are some big unknowns out there. Prudence would say I need to slow down until I figure out what those unknowns cost because those stand a significant chance of making this project uneconomic." Tr. 3280:2-6. To have a reliable capital cost estimate, the Carriers had to perform the due diligence

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burning oil wells and to restart a country's primary industry. Further, that it is telling that the Carriers cannot list a single peacetime oil pipeline project to support their fast-track decision.

[408] Anadarko RB 63.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

necessary to properly scope the project. Scope development must be "comprehensive" and is "the most important phase in the development of any project." Ex. AT-273 at 206.

700. The State argues alternatively, that if the project was to be sanctioned with less detailed engineering than normally prudent, then the execution schedule would have to be pushed back to take account of the inevitable amount of rework, design changes, and scope changes that would occur. However, in this case the schedule was not lengthened before sanction. This led to cost increases and delayed schedule. BP later would acknowledge that this was the result of insufficient project definition early in the project. See below (What happened in 2005). The State also argues that a prudent manager would have accounted financially for the cost and schedule risks inherent in an unrealistically short schedule at the AFE S020 approval process. State IB 178-79. As the State points out, the JPO warned the Carriers that the schedule was "highly aggressive and optimistic." This means that the major milestones should be considered to have a large measure of uncertainty. Ex. ATC-233 at 4. Thus, even the JPO had warned the Carriers that the schedule was unrealistic and the risks were high. The State continues to argue that the Carriers should have at least substantially increased the contingency in project costs and decreased savings based on the tight schedule and uncertainty of meeting deadlines and reassessed project economics. However, the Carriers made no changes to project economics and in fact decreased the contingency at sanction by $4m (to $12m.) Ex. SOA-295 at 2.

701. The Carriers agree that the "original investment cost estimates for the SR project proved to be too low."[409] They also contend that the savings were realized[410] and that they made the decision to undertake a manageable risk in the expectation that TAPS shippers would benefit from substantial cost savings." [411] However, the fact is that the biggest risks were realized, the risk of substantial cost overruns and the risk that savings would not be achieved. In AFE S020 more than $1 billion in savings over the next 20 years were projected. Ex. SOA-60 at 4. These savings would result from unstaffed operations, reduced operating expense, and reduced future major maintenance exposure. *Id.* at 5. The Carriers did not prove that major maintenance costs have been reduced by $1.1 to $1.4 billion over twenty years.[412] Anadarko argues that only minimal savings have been realized.[413] It also argues that even if the Carries' savings estimates were

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[409] Carrier's IB 77.

[410] *Id.*

[411] Carrier's IB 140.

[412] Carriers IB 1.

[413] Anadarko's RB 64.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

correct, it would not make sense to the nonaffiliated shippers for the Carriers to spend approximately $750 million up front in order to take the risk that Alyeska might save a billion dollars over the next 20 years. Moreover, according to Anadarko the impact of adding to the cost of service the costs spent on SR guarantees that nonaffiliated shippers rates will go up even if the "alleged savings" occur in the future. B. Sullivan testified that using the Carriers' own figures, the Carriers cost of service has increased by $104 million because of the rate base increase from 2006 to 2010. Tr. 349:10-350:13. The increase is primarily from the SR project. Tr. 351:2-5. Grasso also testified that there is no benefit to the shippers from the SR project (there is no change in service, throughput or reliability but the costs are higher). Tr. 4305:10-18.

702. It is determined that the Carriers knew of the deficiencies in their preliminary engineering. Even the JPO warned them of the problems with their engineering. The December 2003 JPO letter points out numerous deficiencies in project design. Ex. ATC-233 at 4-6, 9, 16, and 20-21. Sanders testified that the letter pointed out key deficiencies that were experienced later on in the project, such as, a) preliminary design; b) schedule; c)Fire Marshall; and d) power supply assumptions. Ex. SOA-542 at 71:15-17 and 71:8-73:11. As witness Hisey testified, they "knew they were putting in an organization outside of Alyeska's normal process, that you had risks with that. Those are well known. The skill sets, the individuals were known. The scope was known that it was unknown. And again, the assumptions that were made, the way you determine if they are accurate is you do more engineering to test your assumptions. So if you know you are operating off of assumptions, you need to know you stand a risk of those assumptions being wrong." Tr. 3892:11-19.

703. Sanders testified that a reasonable pipeline manager would have interpreted "the December JPO letter as a giant red flag, and would resolve the project deficiencies listed therein before embarking on a fast track schedule with so many detailed risks." Ex. SOA-542 at 70:20-22. The JPO also noted numerous errors in codes used and interpretations of code intent. Sanders also testified that the "failures to understand applicable codes later led to major issues that caused major engineering changes in drawings and specifications-including purchased equipment and fabrication details. Code errors included references to wrong building design codes, Canadian standards rather than applicable US standards, spacing errors and omissions for layout, and other issues that should have been viewed as a major red flag just prior to intended sanction." *Id.* at 73:4-11. The Carriers failure to complete preliminary engineering in accordance with applicable industry standards is unreasonable. Moreover, not changing the cost estimates in the face of these warnings is also unreasonable. As IPA noted (see What happened in 2004 below) any scope changes to the project may alter or invalidate the analysis results discussed in this report. SNC also acknowledge that scope changes will impact costs and schedule especially in a fast track project. (see What happened in 2005 below).

704. The State is correct that control system upgrades and automation of the legacy equipment was technically feasible and achievable without disruption to the operations of

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the pipeline. State IB 197. The studies conducted from 1994 through 2001 corroborate this. *See* discussion supra. For instance the 1994 Control and Telecommunications Long Range Plan recommended specific control system upgrades including installing a mini SCADA at each pump which would allow simplified operations, maintenance and remote diagnostics. It also recommended installing high speed process control data highways at the pump stations. Pomeroy in testimony corroborated this. Tr. 7877-7878:15.

705. The 1997 Bailey Report,[414] the Draft Reinvestment Strategy Study,[415] VECO's Long Range Plan Addendum Report in 1998-1999,[416] AFE-180,[417] Kenonic's Control Systems Strategic Framework Report in 2000,[418] and a Memo from J. Edmunson in 2001[419] all recommended control system upgrades to the legacy equipment. Thus, it is found, that the Carriers arguments that electrification had to be undertaken in order to upgrade the controls is not credible and is contrary to the record evidence and as a result is rejected. The Bailey Report, AFE F180, and Kenonics identify all pump station system equipment that would be automated, not just the main line pumps and drivers. Bailey for instance, identifies 24 systems and describes how each system would be automated from HVAC to Fuel Forwardin Skid Components. As a result, all of the auxiliary turbines, and miscellaneous utility systems would be automated to allow for unattended operation. These upgrades and automation would create staff savings. AFE F180 concluded that it would be able to achieve staff savings by combining control system upgrades with regionalization of oil spill response and maintenance. Ex. ATC-110. The Carriers in this case argue that the staff savings are attributable to electrification. Again it is found that this is contrary to the record evidence and is rejected as not credible.

706. The Carriers allegations concerning the obsolescence of the legacy equipment which prompted its replacement, is belied by its own witnesses testimony. *See* e.g., Ex. ATC-19 at 38:14. Howitt testified the MLUs "were reliable and could have continued to be used for some time to come." Ex. ATC-19 at 109. The record evidence also does not support the allegation of legacy equipment obsolescence. The Carriers' own documents

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[414] Ex. SOA-135. The Bailey Report discusses how upgrades could be done in a staged manner one MLU at a time without disrupting operations with a 3 to 4 year completion. *Id.* at 52, 79, 12.

[415] Ex. SOA-143.

[416] Ex. SOA-134. This estimated approximately four years to completion. *Id.*at 31.

[417] Ex. ATC-110.

[418] Ex. ATC-114.

[419] Ex. SOA-470.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

show that the legacy equipment was functioning well and was highly reliable. There is no controversy on this record concerning the expertise of J. DeHaas with regard to the legacy equipment. He was during the time at issue in this case the Lead Rotating Equipment Engineer. One of the Carriers' witnesses described him as a world wide expert in rotating equipment. Ex. SOA-140. Regretfully, this forum did not have the pleasure of having this witness cross examined since he was not called to the witness stand. However, his clear opinions are well documented in this record. He opined that the legacy equipment was reliable and could continue to operate. Ex. SOA-21 ("the equipment can be maintained nearly indefinitely"; "the mainline units will be operable and maintainable for many years;" there were spare parts to keep the units going; the Cooper RTs were well functioning and reliable). *See also* Ex. SOA-24 (no obsolescence issues with the Avons or with instrumentation); Ex. ATC-149 (the MLU pumps are essentially infinite life); Ex. SOA-473("there are no obsolescence issues regarding the mechanical equipment") and Ex. SOA-25 at 95; Ex. SOA-263 (legacy equirement highly reliable). This documentary evidence, contemporaneous to the time frame at issue in this proceeding is given significant weight. This evidence shows that the MLU Avons were not obsolete. Moreover, throughout 1995 to 2001 the pipeline was 99 percent reliable.

707. B. Sullivan[420] testified that he did not "know of any pipeline that has replaced functioning facilities that still had a significant service value and could still provide useful service to ratepayers with new facilities…" Tr. 355:22-25. Dr. Boyce also testified that the legacy equipment was not obsolete. Ex. SOA-543 at 10; Tr. 1434-35:12-3. He also testified that: [t]he expected life of a machine grows, because if you look at a machine that is even 25 years old, nearly every component in that machine is not more than four or five years old . . . they are being upgraded. So this is a very common thing, that after about certain years, eight years roughly, near all of the components are new. They're all – in other words, you keep on replacing the old designs and keep on replacing the old concepts." Tr. 1447-48:18-5.[421] Dr. Boyce further testified that the legacy equipment can operate in a safe and reliable manner indefinitely if it is properly maintained. There are a large number of Avon gasifier turbines around the world that operate in a safe, reliable and efficient manner. Ex. SOA-543 at 20.[422] C. Sullivan

[420] B. Sullivan has over 25 years of experience in pipeline rate and related matters. He has testified in numerous proceedings dealing in both gas and oil pipelines. Ex. AT-1 at 3-5.

[421] Dr. Boyce questioned the need to replace the legacy equipment. "The question that needs to be addressed when there is already an existing system in place is whether it makes sense to get rid of the existing system and install an entirely new system, when the existing system could be modified to accommodate today's conditions at much lower cost." Ex. SOA-543 at 12-13.

[422] "[T]hese turbines are being installed in new applications around the world. Ex. SOA-543 at 21.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

testified that the legacy equipment was reliable and could have continued to serve for another 20 years. Ex. SOA-1 at 43.

708. Additionally, GE in its July 2002 study also found that the legacy equipment was highly efficient, rugged and durable. Ex. ATC-147 at 22. This is another independent corroboration of J. DeHaas' opinions. Moreover, contrary Carrier allegations are dispelled by the fact that there are legacy MLUs operating at PS 1 as of the time of the hearing in this case. In addition, there are legacy pumps being used for recirculation purposes at PS 7. Further, a scoping study in 2009 found that the legacy equipment was still operating well and the option of maintaining legacy equipment appeared promising. Ex. SOA-574 at 5. However, the option was rejected for economic reasons, so that they would not lose from tariff recovery $91 million in sunk capital costs.

709. The Carriers in this proceeding seek to justify electrification on the basis that the legacy equipment could not handle flows lower than 400,000. The record evidence supports the finding that low throughput was not a basis for the decision to proceed with electrification. J. DeHaas opined on numerous occasions that the legacy equipment could operate at lower flows down to 150,000 barrels per day.[423] Exs. SOA-559 and 660. Additionally, Dr. Boyce testified that the legacy equipment can operate at lower flows. Ex. SOA-543 at 21-43 Tr. 1695-98. He further testified that the power of the Avon gasifier turbines can be turned down to accommodate flows as low as 350,000 BPD by reducing the air flow and firing temperature. Ex. SOA-543 at 33:22-34:1-5. Additionally, he testified that even lower flow rates could be achieved by the legacy MLUs by re-circulating a portion of the inflow at the pump stations. *Id.* at 42:18-43:14. He added that he has operated gas turbines with their bleed valves open for extended periods of time without any problems. Tr. 1538:7-25. Dr. Boyce was a credible witness with 50 years of experience in his field and his testimony is given significant weight.[424]

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[423] He noted that vibration issues had been improved. Ex. SOA-559. DeHaas further stated that the Avons can operate below 6400 RPM which is what would happen at lower flows. He revised the operating procedures to allow this. Ex. SOA-677. He also indicated that the turbines at PS 1 were over-hauled, and tests showed excellent performance at flow rate indications of as low as 150,000 bpd without recirculation. Ex. SOA-559. The Carriers cite a January 2004 exhibit to claim that DeHaas had stated that the Avons could not operate at 6400 rpm. However, they fail to cite SOA-677 and SOA-559 which are 2009 exhibits. They also cite Ex. AT-417 to claim that DeHaas called the Avons to be antique. However, in the context of the e-mail DeHaas is not being pejorative concerning the Avons.

[424] Dr. Boyce has written extensively on turbines and has experience installing and maintaining turbines around the world and has taught classes on turbine engineering at universities all over the world. Ex. SOA-543 at 1-7. *See also* Ex. SOA-657. He has experience in the field of pipeline pumping stations, power plant engineering and turbo-machinery. Additionally, Dr. Boyce has received a number of awards recognizing his

20140227-3052 FERC PDF (Unofficial) 02/27/2014

710. As stated above, PS 1 currently operates with legacy equipment. Ex. SOA-699. TAPS witness J. Scott's testimony that the turbines could not operate at low flow because they could not operate below 6400 rpm with bleed valves open[425] has been discredited both by his own testimony and the testimony of B. Howitt and Dr. Boyce. First, J. Scott admitted he has no experience operating the Avons at low RPMs and had never tested a turbine running with bleed valves open. Tr. 5607:5-8, 5616:4-12. Second, Scott acknowledge that with recirculation piping and valves on the legacy equipment, there would be no need to turn down the pump speed, and by recirculating a portion of the oil, the legacy pumps could continue to operate at higher speed even with declining throughput. Tr. 5642. Third, B. Howitt admitted that the turbines at PS 1 are currently regularly operated at or below 6100 RPM for prolonged periods of time (this is below 6400). Tr. 6769:1-8. He further admitted that at these RPMs the bleed valves are open. Tr. 6768:17-6769:3. Moreover, TAPS has operated at throughput levels of 300,000 bpd. Tr. 4000:17-4002:1; Ex. AT-253 at 6.[426] Further, Alyeska in 2001 anticipated that it would be able to operate at throughput levels contemplated in a 30-year period. *Id.* Alyeska, could have modified TAPS to include additional recirculation capacity or overhauled the Avons to obtain better performance at lower flows. Thus, it is concluded that the legacy equipment could have operated within the same lower range of throughput as the new equipment.[427]

711. The Carriers also identify the turn-down capability of the electric motors, variable speed drives and new pumps as a benefit of SR. Carriers IB 118. However, as stated in the previous paragraph, this was not a reason to change the legacy pumps in the first place. After SR the minimum contingency flow for TAPS is estimated to be 300,000 bpd. Ex. ATC-19 at 126. Howitt testified that "we believed that, following the SR project, Alyeska would be able to avoid a cold re-start scenario so long as there was throughput of at least 300,000 barrels per day. But we never expected that the pipeline

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expertise and contributions in the field of turbo-machinery and has been elected to a variety of honor societies in engineering. *Id.*

[425] Ex. ATC-741 at 5-8.

[426] The original design capacity of TAPS without DRA was 1.42mbpd. The design capacity of SR is 300,000 mbd to 760,000 mbd. Ex. AT-291 at 1787. A decision was made in 2003, by the Carriers to reduce the design capacity of TAPS with the SR project. Ex. AT-291 at 676. Use of DRA increased the original design capacity to 2.1 mpd, while DRA only increases the SR design capacity to 1.14 mpd. Ex. AT-291 at 676-77. Thus the SR equipment cannot accommodate flows as high as the legacy equipment has already accommodated.

[427] Previous work indicated a minimum throughput rate of 300,000 bpd using the Avon-driven pumps. Ex. SOA-11 at 17.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

would be operated continuously at that minimum contingency level. Rather, . . . we believed that throughput would still be in the 400,000 to 600,000 barrels per day range by the end of our 20-year planning period for the project." *Id.* [PRIVILEGED MATERIAL REDACTED] Ex. SOA-554. Based on the throughput projections the benefit of operating at 300,000 bpd may never be used. Further, the Carriers cannot achieve the minimum design flow of 300,000 bpd without additional modifications which could cost from $500 million to billions and significant increases to the operating costs. Ex. SOA-148 at 3. Thus, this post hoc rationalization of the benefits of SR is not given any weight.

712. The Carriers assert that cold-restart is another benefit of SR. Carriers IB 80-81. The testimony of Carrier's witness Baldridge is totally discredited and not given any weight. He testified that but for electrification cold restart capabilities were not available in the legacy equipment citing an incident in January 2011. Ex. ATC-28 at 21. First, the legacy equipment had a cold restart policy. Ex. SOA-542 at 77-78 and SOA-604.[428] They recirculated oil through certain stations to prevent ice build-up. This was consistent with the policies in place for the legacy equipment. Ex. SOA-542 at 77:11-13. The legacy equipment generated substantial amounts of waste heat that could be used to ameliorate any oil cooling problem. Tr. 3720:8-17. Moreover, the legacy equipment had better capability to add waste heat to the oil, which would have aided in cold restart situations. Ex. SOA-542 at 77:22-78:3. Significantly, they restarted legacy pump 7 to recirculate oil. *Id.* at 77:17-18; Tr. 6771:7-10. Further, the Carriers have installed a permanent recirculation loop at PS 7 (a ramp down station not electrified) to restart the pipeline after a winter shutdown. This work started in June 2011. Ex. SOA-607, 542 at 78:11-18; Tr. 6771:7-10. Howitt also confirmed that the legacy equipment at PS 1 could also be modified to add heat. Tr. 6771:17-25. Baldridge knew about PS 7 when he filed his testimony. Thus, his testimony is not given any weight. Moreover, until recently the Carriers ignored a significant benefit of the legacy pumps. Tr. 3720:8-3721:1. Consequently, the Carriers have recognized the advantages of using the legacy pumps to add heat to the oil stream and cannot credibly claim that the legacy equipment could not

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[428] This possibility was discussed in the January 18, 1999, Reinvestment Strategy Study. Ex. ATC-105 at 11-12. In December 2000, Alyeska in conjunction with the JPO developed a cold-restart procedure for the legacy equipment. Ex. SOA-604. [CEII MATERIAL REDECTED]

Ex. SOA-628. Hisey explained that recirculation could have been added to the legacy equipment. Tr. 3707:9-3708:9. The January 18, 1999, Reinvestment Strategy Study also found that the legacy equipment generated substantial amounts of waste heat which could be recovered and used to provide heat to the PSs and help ameliorate any oil cooling problems (such as waxing) as flows decrease. Ex. ATC-105 at 11-12; Tr. 3720-21. Pomeroy confirmed that during conceptual engineering they were aware of this advantage but that it was not included in their analysis. Tr. 8108:18-25.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

be used to restart TAPS during the winter. As a matter of fact, Carrier witness Scott confirmed that recirculation could be used with the legacy equipment to add heat. Tr. 5643:24-5644:3.

713. The Carriers admit that the decision in 2002-2003 to proceed with electrification instead of hybrid was not based on a perceived operational need to replace the legacy units at that time. Carriers RB 95. Now they claim that 10 years later this decision has nothing to bear on the suitability of the new equipment, and whether the costs of the new equipment, incurred as a result of the Carriers' proactive replacement of that aging equipment should be excluded from rates. They now claim that when viewed in today's perspective, SR is justified as a lifecycle replacement project, as well as a cost reduction measure. *Id.* The Carriers cannot substitute their new theory of the case for the determinations they made in 2003 to proceed with electrification. When the evidence of what was known to them at the time is considered, lifecycle replacement was never discussed. They offer no proof for this contention and as they continually assert throughout their brief, prudence looks at what they knew at the time. Today's perspective is hindsight and frankly irrelevant.

714. In the renewal application for the right-of-way for the pipeline the Carriers represented that "TAPS physical life is considered virtually unlimited" and that the design life for TAPS was "based on the preparation of robust components" and "state-of-the-art" technologies. Tr. 8388; Ex. ATC-165 at 3. This corroborates that obsolescence or aging of the equipment was not a reason for SR.

715. Likewise, the testimony that hybrid could not have implemented a regional maintenance plan is not supported by the record evidence. Ex. ATC-891 at 14:19; ATC-898 at 41:20; ATC-917 at 17:7. Specifically, Carrier witness J. Johnson testified that the legacy equipment would require on-site maintenance personnel at each pump station, and thus would have required personnel to be housed at PS 3 (rather than at a maintenance facility at PS 4) because personnel could not travel between the pump stations in inclement weather. Ex. ATC-891 at 14:19. However, as far back as AFE F180 the regionalized maintenance and oil spill plans were recommended for the legacy equipment. Ex. ATC-110. Additionally, the evidence in this record shows that the Carriers have represented to the State that maintenance personnel can travel between PS 3 and 4 in inclement weather, the trip would take less than 3 hours in the worse conditions. Ex. SOA-713 at 15. Carrier witnesses also testified that in 14 years the service road between these two pumps had been closed two times. Ex. SOA-712 at 15-16; Tr. 6936:20-24. Moreover, the gate logs for PS 3 and 4 show that significant numbers of people are at both stations day and night. Exs. SOA-700-707. Alyeska also continuously operates a "fly camp" at PS 3. This provides living and dining facilities and offices. Tr. 6875:8-12; 6877:6-24; 6891:21-24. Thus regional maintenance and oil spill could have been done with the legacy equipment or the hybrid option.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

716. BP constructed a pipeline at the same time as the SR project and used the same turbines and technology as the legacy equipment. Ex. SOA-601 at 21-23.

717. Many of the buildings slated to be taken out of service are still in service. Tr. 6661-6735; Ex. SOA-679-SOA-684. The Carriers did not have any "gap document" to identify the difference in controls from the AVON/Cooper drivers and any standard electric drivers. Tr. 7303:18-25.

718. The scope issues continued. In September 2003, Tudor sent an email to Yaege of Conoco, and Bolea of BP, stating that there had been significant scope and cost growth between gates 2 and 3, which had not yet been explained. Ex. SOA-183; Tr. 4933:3-4934:12. It is determined that the Carriers knew, prior to sanction that the scope was not well defined.

719. In September 2003, the Carriers were informed of the Conclusions of a study which was a Comparison between Direct Turbine and Electric Motor Driven Pumps. Ex. SOA-165. As stated above, the conclusions stated that there was a viable alternative for 2, 2, 2, 2 turbine driven pumps at stations 1, 3, 4 and 9. This was the lowest capital cost solution. Ex. SOA-165 at 16. *See also* Ex. ATC-212 at 23-24. This was not studied any further because of the focus on electrification and the belief that a change of concept at that time would delay the "current 2005 completion schedule." Ex. SOA-452. Note that this study included producer conditions to make a determination in favor of electrifying the pump stations. This is squarely in contrast to the Carriers' arguments that they are independent entities. Moreover, it begs the question if they are independent entities, affiliate producers concerns should not have been considered when making such an important decision for the pipeline. The inclusion of affiliate producer considerations tilted the scale in favor of electrification which was definitely not the most economical in terms of initial capital costs. Even though the costs of the "direct drive option were lower without the apportionment." Ex. SOA-165 at 14. Note also that electrification assumed that both PS 1 and 9 would be tied to the grid. Additionally, the exhibit states that maintenance and reliability of constant speed generator turbines should be better than variable speed mechanical drives turbines. Ex. SOA-165 at 15. Additional capital requirements for power at PS 1 or PS9 will increase costs of the electrification option. *Id.* at 15. The study stated that the direct drives turbines are a viable alternative with the lowest capital costs. The alternative of mixing direct drives and electrification could reduce costs more but requires further study prior to sanction. *Id.* at 16.

720. The Carriers argue that the prudence test does not require that every possible alternative be evaluated and that it gives them latitude to make decisions. The Carriers are correct that this is the test. *See Dakota Gasification Co.*, 77 FERC ¶ 61,271 at 62, 154. However, the test also requires the Commission to look at what a reasonable regulated utility would have done. In the context of the facts of this case, the actions of the Carriers were not reasonable. Their decision to fast track the schedule and not look at

20140227-3052 FERC PDF (Unofficial) 02/27/2014

viable lower costs alternatives, are not the actions of a reasonable utility based on the facts that they had at the time.

721. In November 2003, Tudor (Exxon) was concerned with the abandonment of the hybrid case and stated that this makes it impossible to accurately compare the proposed project versus the next-best alternative. Ex. SOA-183. Yaege testified that hybrid was always a comparison point and was never supposed to have been pursued. It is determined that the Carriers did not do their due diligence in comparing viable alternatives.

722. Anadarko argues that the Hybrid Configuration Study shows that less than three months before sanction, there was no consensus on whether or not electrification would allow the Carriers to remove "most of the existing infrastructure." Anadarko IB 94. Ex. SOA-163 at 8. Anadarko is not entirely correct, the cited document clearly states that "the determination of which buildings would remain didn't occur until later in the preliminary engineering effort. This determination was set out in the Building Services Study by SNC." *Id.* at 6. However the building study did not consider gas compression requirements. *Id.* Thus, even though some studies had been conducted for retained buildings, the studies were not complete. As noted above, the assumptions in the Hybrid Configuration Study are found not valid. For instance, the document notes that the electrification option removes most of the existing infrastructure. "As we have moved through preliminary engineering we have found that there is an increased requirement for retained buildings . . . [t]hese retained buildings are rewired to the new Load Centers. This is also true for the Hybrid case. Clearly both cases are complex in this regard but the Hybrid case includes the additional complexity of doing major work in the operating Main Line Pump building. In the Electrification case, work on the new facilities is mostly performed outside of the operating area with the exception of the tie-ins." *Id.* This electrification assumption proved to be incorrect. It is found that again, the Carriers ignored the complexity of the work involved.

723. Flood testified that the inputs into the probability analysis of SR done in December 2003 (Ex. ATC-236), prior to project sanction, were not correct, and could not explain why the costs of SR were so high. Tr. 5305:6-13; 5310:22-5311:3 and 5303:11-18. However, he did admit that Conoco did not independently confirm that the PMT used the proper scope. However, the Risk and Cost Probability Distribution Analysis stated:

> Electrification case uncertainty is dominated by construction cost uncertainty and annual operations cost uncertainties, particularly with regard to project quality outcomes. If project quality is poor, expected efficiencies in maintenance and support efforts may not be fully achieved, and/or the company may not be able to operate the stations unmanned. Meanwhile, construction cost is affected by uncertainty in scope and cost for installation and by uncertainty in the supply of equipment and labor.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> Additional uncertainties for electrification include transition costs and quality of management of change during transition.

Ex. ATC-236 at 2.

724. The Carriers held a "constructability review" in September 2003. Ex. ATC-194 (agenda for meeting). However, critical documentation was not yet complete, thus the success of the review is questionable. Ex. ATC-195 (summary of the meeting). Livett admitted that these documents were not available to the participants at the constructability review because they were not complete: project execution plan; contracting strategy; project commissioning plan, and resource loaded project schedule. Ex. ATC-25 at 8:19-9:5. As of November 2003 "some of the requisite documentation was not yet complete.

725. Thus, the Carriers knew there were scoping and other risks inherent in the project. A reasonable utility manager would have resolved the uncertainties and reduced the risk of cost escalation by undertaking final engineering before proceeding with construction. As Hisey testified, the risk analysis "should give you pause to make certain that you have those risks, you know, clearly defined and nailed down. And the only way you can do that is to do more engineering to get yourself better defined on scope. So I would say yeah, a reasonable, prudent manager would take those into account and know that you are going forward at your own peril of cost overruns and schedule." Tr. 3849:11-17. Stated another way, Hisey testified, that the "greatest driver for the increased costs was lack of scope definition. Ex. AT-230 at 14.

726. Anadarko and the State are both correct, the Carriers knew that they did not know the full scope of the SR project. Tr. 3276:22-3277:22; 3278:14-3279:7; 3280:2-14; 3890:4-10. To reduce the scope risks of a project, as well as have a better understanding of the economic benefits, it was necessary to proceed with final engineering before beginning with construction. Tr. 3782:15-3786:19; 4035:18-4037:2. However, the Carriers had predetermined the completion date and that drove the schedule. Consequently, they did not have time to complete engineering before beginning construction. As Hisey testified, but "you had to have it done by December '05 to get [the tax] advantage. That's what set that schedule. That schedule was impossible. And because they had that schedule, they didn't have adequate engineering to get a good cost estimate. And they didn't get a good cost estimate because they didn't have a full scope of work." Tr. 3023:21-3024:1 and 4035:18-4037:2. Hisey was a credible witness, with years of experience in Alyeska, owner companies and Alaska. Thus, his testimony is entitled to significant weight. Yaege explained that she was pushing very hard to get the SR Project through in order for the Carriers to get quickly to the savings. Tr. 4788:21-4789:8. AFE S020 stated that realizing organizational savings as quickly as possible is leveraging. . . Delay of the project will result in lost O&M savings, lost tax benefits, [and] increased major maintenance costs (including fire and gas upgrades). As Hisey testified the economics of the project were marginal and you had to complete the project

20140227-3052 FERC PDF (Unofficial) 02/27/2014

by a certain time to make the economics work. Tr. 3233:12-3235:17; 3644:16-3647:4. If the costs and benefits had been properly determined, if the project had not been accelerated a prudent manager would not have sanctioned the project. Tr. 4035:18-4037:2.

727. Two months prior to sanction the Carriers had not determined the power supply for electrification. In December 2003, the JPO questioned the reliability of the power supply from GVEA to PS 9. Ex. ATC-233 at 21. After sanction the Carriers were considering the possibility of third-party supplied power at PSs 3 and 4. Further, they sanctioned electrification without knowing the power source for PS 1.

728. C. Sullivan identified material deficiencies in the supporting documents for AFE SO20. First, the schedule was not resource loaded, and did not fully integrate the engineering and construction activities. Second, work packages with final designs were not available. Third, the project schedule contained only approximately 400 activities, which is far too few for a project estimated at over $250 million. Fourth, insufficient FEL scope of work. Fifth, construction bid documents were not finalized. Sixth, piping and construction diagrams ("P&IDs") and the plot plans were not finalized. Seventh, hazard and operability and process hazard analysis reviews were not completed. Eight, project turnover deliverables were still not available. Ex. SOA-1 at 167-168. This is indicative that the costs were unreliable and the Carriers knew this.

729. Additionally, the Carriers knew that the contingency for the project was understated. The cost estimate had a contingency of less than 7 percent (16,539,000/242,000,000). Ex. SOA-60 at 8. The Bailey Report included a contingency of 30 percent and this was just for automation (did not involve electrification). Ex. SOA-737 at 18. Thus, the Carriers knew that the contingency was understated.

730. As Pomeroy testified, the Carriers did not address any "infant mortality" issues of the new equipment in their electrification proposals. Tr. 8026:19-23. Consequently, they did not know the likelihood of the new equipment breaking down.

731. Prior to sanction, the Carriers did not consider, the inefficiency of converting gas power to electricity, to run an electric motor or, of replacing fuel-fired pump drivers with electric pump drivers, which required generating electricity from fuel-fired generators. Pomeroy testified that in general, it is inefficient to convert something to electricity, to then run an electric motor but this was not considered since there was no significant value associated with the gas. Tr. 8059:7-19. Pomeroy did not know the efficiency of the Siemens turbines. Tr. 8079:25-8080:1. See discussion for year 2009, below.

732. The PMT was staffed with individuals that did not have the correct qualifications. The Carriers arguments[429] to the contrary are not supported by the record. Barrett

[429] Carriers IB 147-50.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

acknowledged that the person he selected to manage the automation portion of the project, P. O'Farrell, had never before worked on the Alyeska control system. Tr. 5868:19-21.

733. The Carrier's witnesses testified that the economics for the SR project were marginal. Howitt testified that from the beginning, the economic benefits of the project were considered by the Carriers to be "marginal." Tudor testified that even at approval of preliminary engineering the project was considered marginal. Tr. 4949:9-13. As noted above, Tudor on November 12, 2003, expressed concern with a number of things and stated that the project had a rough ride through Gate 2 based on "marginal returns". Ex. SOA-183. Tudor further testified that from the beginning, the project had a lower rate of return than Exxon would typically expect on a project of similar in size. Tr. 5044:11-14. Another email from Exxon dated April 24, 2003, notes that Exxon at Gate 2, was not sold that Electrification was the better alternative to Hybrid and additional contingency might push us to a different answer (risk that EM would not approve the project)." Ex. SOA-256. Yaegge testified that "when [the new pump station concept] first came forward, my intuition told me that it would be prohibitively expensive." Tr. 4802:10-23; 4803:24-4804:5. "You know, I think because I knew what it cost to build the Trans Alaska Pipeline originally, and I presumed that the portion of that was pump stations was a reasonable portion of that, and when you put inflation on top of that, I thought we were talking numbers that started with a B." *Id.* at 4803:24-4804:5. Thus, the Carriers were concerned about the costs of the project very early on.

Conclusions 2003

734. The record supports a finding that one of the reasons for SR was that the pump stations were reaching the end of their economic life. The statement is interpreted to mean the assets were close to total depreciation. There are no studies in this record showing that the pumps were obsolete or in any way degraded. On the contrary, the record shows the pumps were operating exceptionally well.

735. The record also supports the finding that the way the SR Team was set up was not conducive to effective participation by employees in Alyeska's Engineering and Operations. Many concerns raised by these employees were ignored during preliminary engineering.

736. The hybrid to electrification comparison was not valid among other reasons because the studies done were at different level +/- 30% for hybrid, +/- 15% for electrification. The configuration for the pump stations, PS 9 in particular is different between preliminary engineering and the presentation to the owners in November 19, 2003. The Gate 3 deliverables will not be finished until after sanction. If in December 2003, the Economic Evaluation Report states that the Long Range plan is based on electrification, then they had already made the decision on electrification even before they sanctioned SR.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

737. The Carriers themselves considered the cost estimates of Hybrid suspect. As a result, these estimates (cost and savings) are not given any weight. To wit, Ex. SOA-13 states the Hybrid alternative was not as thoroughly evaluated as the reconfiguration alternative. *Id.* at 12. Therefore, the confidence level for Hybrid cost and savings estimates are lower than those of the reconfiguration alternative and electrification options. Ex. SOA-13 at 12. For major maintenance savings the assumption is, that avoided major maintenance is 28% capital and 72% expense, based on a review of PS1 avoided projects. *Id.*at 12. Pomeroy's testimony in this regard is contrary to this document and not given significant weight. Ex. ATC-898 at 45-46.

738. Staffing reductions are not credible. Different documents show different numbers. For instance, compare the staffing reductions in Ex. SOA-13 (285 reductions for electrification) with Ex. SOA-136 (373 staff reductions). There is no explanation on this record as to why these figures are different.

739. In their quest for savings in a marginally economic project the Carriers did not slow down and do the industry standard engineering work. They moved forward with a poorly designed and insufficient schedule with zero float and zero contingency. Exs. SOA-197 at 9 and SOA-232 at 7. They kept going even when personnel complained they were having problems keeping up,[430] that schedule compression is causing gate review activities to converge,[431] and that preliminary engineering "feels rushed, which is perhaps one of the biggest factors getting in the way of careful and deliberate coordination."[432]

740. It is concluded that the failure to complete preliminary engineering in a reasonable manner was a substantial failure to comply with standard industry practice. This led to incorrect assumptions such as: they would not have to spend money on fire and gas upgrades to meet code requirements (so these costs were excluded from the estimates)(Ex. SOA-542 at 64:8-11); availability of electricity from the utility at PS 1 and 9 (underestimated the costs at these stations) (Ex. *Id.* at 64:12-15) and the viability of parallel construction (underestimated the costs of construction - parallel construction converted to sequential) (*Id.* at 64:19-21). This failure also led to unreasonable project schedules without sufficient contingencies. *Id.* at 64:16-17. It was imprudent to proceed with the project without developing a reliable cost estimate. Until a project's scope is clearly defined, it is impossible to develop a reliable cost estimate. The starting point for the cost estimate is the appropriate definition of the engineering scope of the project.

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[430] Ex. SOA-453.

[431] Ex. SOA-232 at 7.

[432] Ex. SOA-280.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

741. "Effective project management starts with a well-defined scope of work, which should support a realistic cost estimate and schedule. Proper project definition at the start is one of the most critical aspects of project success. Inadequate project definition is one of the leading causes of project scope growth and changes, and overall project cost growth and schedule delays." Ex. SOA-275 at 101. As the State points out, developing the project scope prior to starting execution allows informed decisions to be made about not only the project schedule and budget, but also critical components including equipment, contractors and staffing levels.

742. Establishing the appropriate engineering scope provides a reliable cost estimate and minimizes unexpected cost overruns. The book Industrial Megaprojects by Edward W. Merrow establishes that "FEL-2[433] develops and articulates the scope of a project to a point where we can be confident that all elements of scope are accounted for." Ex. AT-273 at 206. Barrett agreed with this and stated that he considered this very important and must be very comprehensive. Tr. 5875:14-17; 5874:21-5875:1. Barrett also agreed that the higher the project definition of the scope the lower the level of uncertainty. Tr. 5832:11-12. He also testified that "as a project gets more defined, that the range of estimate becomes tighter." Tr. 5808:6-8. Barrett confirmed the Carriers were aware that automation projects are complex. Tr. 5809:15-23. Additionally, he confirmed that the Carriers knew that they would have had a more reliable cost estimate if the engineering had been more complete. Tr. 5807:9-17. Further, Barrett also admitted that the Carriers knew at the time that automation programming was so complex that they searched the world to find someone capable of programming it, including someone in the Middle East. Tr. 5827:10-16. Barrett testified that the Carriers should have known that the "self-contained modules" were going to require a tremendous amount of cabling and wiring in order to integrate with the existing system. Tr. 5842:10-25.

743. M. Tudor in his deposition stated: "it is a revamp project that is taking existing facilities and creating a different reality with them. And those projects inherently history tells us sometimes are more complex, and more difficult to execute than other projects." Ex. SOA-267 at 32 (deposition page 125:11-16). Howitt also testified that "major projects like this are much more complex sometimes than they are originally viewed to be and that tie-ins to your pump station where you're interfacing with new equipment are very complex and you are going to find things you didn't expect." Tr. 4567:10-15. Notwithstanding all of the above, the Carriers went ahead with the project. It is found that the Carriers (and their affiliates) as Anadarko points out, sophisticated multinational companies, knew or should have known these principles.

744. Notwithstanding all the red flags noted above, the Carriers did not slow down and carefully scope the project. They ignored the red flags and the internal experts. They

[433] The book describes two FELs. The FEL-1 is about developing the Business Case for the Project. Ex. AT-273 at 202. FEL-2 is about scope development. *Id.* at 207.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

knew they were doing this, and they should have known and/or knew that this would not have a good outcome. They knew that the scope was not adequately defined prior to sanction. If reasonable industry practices had been followed by the Carriers, they would have reasonably completed the preliminary engineering addressing all the critiques and objections of the experts before submitting AFE S020 for approval. The Carriers' actions thus, were imprudent. As Anadarko points out, the Carriers' most significant failure was to proceed with a project that they knew was undefined. A fundamental misunderstanding, based on the failure to complete final engineering, led the Carriers to grossly underestimate the scope of the project. They viewed the project as a greenfield project, with new electric motors,[434] drives, and pumps which would be placed in a module, the module brought to the site and then plugged into the existing facilities.[435] In order to achieve the savings the project required automation. Thus, the project was a more complicated brownfield project, in which most of the work and cost occurred outside of the module.[436] This had to occur while TAPS was still operating.[437]

745. The Carriers argue that IPA reviewed the level II schedule and found that the schedule "clearly identifies the critical path and . . . is loaded with project resources for

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[434] The assumption for the electric motors was that off-the-shelf technology would be used. Tr. 3067:13-16; 3440:6-14; 3444:2-7. However, the electric motors had never been built before, the design they used had not been used before, the MLU train had not been built before. The pumps were serial number 1 pumps. Tr. 3067:16-20; 3434:15-3435:18; 4026A14-4028:3. The motors and the modules had to be redesigned. Tr. 3441:12-21; 3442:23-3443:5; 4028:4-19. The project was experiencing problems with the motors as late as February 2005. Tr. 4025:10-4026:13. Consideration was given to buying motors from a different company. Tr. 3442:23-3443-5. The motors issue led to delays in the project. Tr. 3446:15-19.

[435] Tr. 3024:2-25; 3029:9-3030:1; 3065:18-3066:7; 3066:22-24; 3279;14-20.

[436] You had to integrate the module with the existing facilities. You had to change out the control system, not just in the new modules but connected to the old equipment. You had to change out all the communications systems. Tr. 3024:2-14. You had to take into account the retained buildings, all the support facilities and shops and warehouses. Tr. 3035:21-25. In addition, you had to take into account changing the OSCP, new OCC and relocating the OCC as well. Tr. 3036:1-10. You had to do tie-ins, pilings and running new pipe. Tr. 3067:1-8. Additional costs were the cabling, the fire marshal issues to be resolved and telecommunications issues. Tr. 3279:22-3280:1. Further, all the processes and procedures for tagging and records. Tr. 3031:15-18. They had to account for the size of the backup generators. Tr. 3926:9-10. They made errors in the electrical code requirements. *Id.* at 11-12.

[437] Tr. 3024:6-15; 3031:10-18; 3035:18-3036:10; 3065:24-3067:8; 3279:20-3280:1; 3923:15-3924:14; 3926:3-3927:11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

all activities[, and t]he schedule includes all project phases from definition through startup." Carriers RB 62. They omit the IPA disclaimers and other things pointed out by IPA, for instance, that the level of definition in the site-specific factors shows some gaps. Ex. ATC-258 at 3. Most importantly, the following language: "[i]n all, the team has defined the project to a level that positions it to attain its set objectives. A remaining risk is that of significant changes to the design after the start of execution. Late design changes lead to cost growth and schedule slip. In order to maintain current cost and schedule competitiveness, the team should remain aligned on the project objectives and adhere to a strict no-change policy." *Id.* This was really the risk that the Carriers assumed "a strict no-change policy." They cannot call their actions reasonable when they did not follow the advice of the third party reviewers.

746. Anadarko is correct that the Carriers knew and chose to ignore knowledgeable Alyeska personnel as well as the body of work that Alyeska had developed over several years regarding how best to upgrade TAPS. The Carriers ignored detailed Alyeska reports that indicated (1) electrification of the MLUs was not the most viable or economically sound alternative at any location and was a particularly poor choice where there was not access to a reliable electrical power grid; (2) automation of the control system alone would take several years of planning and implementation; (3) tying specific staffing levels to any particular operating MLU was speculative at best; and (4) an upgrade project should be phased or prototypes used so learning can inform the process.

747. The Carriers had numerous employee interviews to get their input before they began SR but then they ignored what they were told and also ignored that not a single employee proposed electrification of the MLUs. Tr. 5522:25-5523:5; Ex. ATC-21 at 6. The Carriers knew and ignored that improving TAPS was a complex challenge of integrating new control systems into an operating pipeline analogous to "changing a jet-engine in mid-flight." Tr. 4606:4-11. They knew that automating TAPS was more complex than simply installing pre-wired truckable modules and that the complexity grew with the level of automation. This had been established by the Bailey Report. Ex. ATC-102 at 25; Tr. 7860:16-19.

748. Additionally, the Carriers knew that the Reinvestment Strategy Study had recommended improving the current base case using the AVON drivers. Ex. ATC-105 at 17. Electrification of PS 7 and 9 had been considered in this study and rejected as not feasible since the existing grid at GVEA was not a reliable source of electricity and still required fuel-fired generators as back-up. *Id.* at 14-15. In addition, the VECO Report estimated that completion of the control systems upgrades would take approximately five years to complete, including four years from preliminary engineering through implementation. Ex. SOA-134 at 31. At that point in time Alyeska had already spent two to three years in developing conceptual engineering, so the project was really a seven-to-eight year project. In 2001 an Owner Technical meeting quoted Kenonics as estimating the project would take "4 to 5 years to complete." Ex. SOA-233. The report described the scope as too ambitious for the schedule, and for the project to be completed

20140227-3052 FERC PDF (Unofficial) 02/27/2014

within the estimated time, "significant effort would need to be performed in parallel, with the high probability that pipeline services might be disrupted." *Id.* at 2. Conversely, if the scheduled remained as estimated cost overruns are likely. *Id.* at 4. Further, a warning stated that "[k]nowing your requirements on the front-end is critical" because "[o]nce you start down this path to upgrade your controls and SCADA systems, it is very difficult to stop." *Id.* at 4. The final Kenonics report in 2000 estimated the implementation schedule for the control systems upgrades to take approximately five years to complete. Ex. SOA-156 at 81. Therefore, it is found that the Carriers knew that the 22-month schedule for the SR project was unrealistic and showed that the project scope had not been developed. Additionally, the Carriers knew and ignored that experienced leadership is necessary for a project to be successful, and they failed to provide effective leadership to the SR project.

749. In 2001 the Carriers' also questioned whether the benefits would indeed come to fruition or whether they would end up with fully automated and fully manned sites. Ex. SOA-233 at 4. They also questioned whether regulatory issues would prevent them from reducing staff. *Id.* at 4. Therefore, it is concluded that they were aware that the staffing of the pump stations was at issue and needed further study. The record in this case does not support the estimated staff reductions claimed before sanction. In fact, the pump stations are still manned even though significant investment has been made on the pipeline. The 2001 document states that the Carriers may want to look at other options to upgrade equipment which are less costly if the staff could not be reduced substantially. Ex. SOA-233 at 4. Anadarko is correct that the Carriers ignored prior due diligence which warned that the project scope was unrealistic and failed to exercise reasonable due diligence.

750. The Carriers claim that they were diligent in sanctioning[438] and implementing the project. They claim that SNC achieved the goals set by the Carriers: (1) a design for each pump station at preliminary engineering and (2) updated cost estimates with +/- 15% accuracy. Carriers IB 41-42. However, the Carriers' own witnesses contradict these statements. Carrier witness Barrett testified that at sanction he was "very clear" with the Carriers that engineering was only 30 percent complete; and they would have to expect some changes because of the uncertainty. Tr. 5805:13-25. In December 2003, Larkspur reviewed the estimates and reported that they did not agree "that the quality of this estimate falls within" the +/-15% as reported. Ex. SOA-222 at 3. It pointed out several problems with the engineering, including the lack of a project execution plan, failure to define scope of work on existing buildings, and insufficient development of the electrical and instrumentation scope of work. *Id.* at 2, 7, 9. Larkspur also stated that it had "major concerns that the project as currently designed could be built for the current estimated

[438] Anadarko is correct that the Carriers' misquote C. Sullivan's testimony. He in fact testified that the performance in preliminary engineering was unsatisfactory. Tr. 2186:13-16.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

value." Ex. SOA-222 at 13. Further, again in January 2004, Larkspur reiterated its previous conclusions in a follow up report.[439] This was prior to sanction. Ex. SOA-223 at 14. Thus, the Carriers knew at sanction that engineering was only 30% complete as reported by Barrett and was not +/- 15% as resported by Larkspur.

751. The evidence in this record further disputes the Carriers claim of diligence. For instance in a letter discussing SNC's proposal to undertake preliminary engineering of electrification SNC wrote "[t]o further display our keen interest in helping ALYESKA with the success of this project, the proposed Project Manager, Reg Pole has contemplated key issues that . . . can reduce the project schedule. Those key issues include: …The assumption that the conceptual work has met all of ALYESKA's objectives and the conclusions of that work should not be revisited." Ex. ATC-180 at 3. As the State points out, this is not a reasonable approach since the purpose of preliminary engineering was to verify and refine the assumptions of conceptual engineering and provide better estimates for equipment, construction costs and savings. AFE S020 required the following: (the project will be managed using FEL methods that the industry recognizes as best practices)(preliminary engineering reduces financial risk by eliminating unnecessary scope before the implementation contractors are involved) (the design can be sufficiently developed to enable design reviews.. ahead of procurement and construction) (optimized design). Ex. ATC 165 at 5. The State is correct that if assumptions from conceptual engineering are accepted without validation, it is not possible to verify and refine such assumptions. The SNC letter also suggests eliminating one of the design reviews (probably the 50% review). Ex. ATC-180 at 3. Again, this is not an industry best practice. The SNC letter should have been a red flag for the Carriers. Instead the Carriers hired SNC. It can only be concluded as an inference from the letter, that SNC was willing to cut corners to comply with the Carriers predetermined schedule. This is exactly what happened, best industry practices were not followed, contrary to the Carriers assertions in this case.

752. The Carriers argue that their internal requirements for approval of a project such as SR are "extensive and demanding" and that the Carriers had to obtain approval from their respective parent companies (BP, Conoco and Exxon). Carriers IB 132. However, Carriers' witness Yaege testified that in the decision to sanction the project, her team did

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[439] An email from December 17, 2003, shows that the costs estimates were being increased in response to Larkspur by $1.9 million and this did not include two additional items still being reviewed. Ex. ATC-234. An email from Barrett to Livett, in December 18, 2003, dealing with the Larkspur report supports the fact that the Carriers knew that 'we will need to manage costs, … very carefully" "there is no fat in the estimate (which we strived for) and we may be a little light on contingency." Ex. ATC-235. Contrary to the Carriers assertion this does not sound like the PMT "remained convinced of the soundness of our cost estimates that had been derived over the course of a very exhaustive conceptual and preliminary engineering process." Carriers RB 54.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

not do any additional work, they just looked at what had been developed. Tr. 4811:4-19. She also testified she was responsible for the ultimate decision made by Conoco and that no one at Conoco checked the scope of the project since they did not have the skills to review the details. Tr. 4767:5-24. Additionally, Yaege testified that she did not conduct a detail review of the estimated projected savings or the methodology for determining the projections. Tr. 4794:23-4795:9. She relied upon Carriers' witness Flood for the details. Tr. 4735:4738. Flood testified that he reviewed the work of others. Tr. 5348:8-24. Carriers' witness Tudor testified that he did not read the IPA final report and did not know that the IPA analysis is only for the scope of the project presented to it. He was aware of the "poor" front-end-loading status in the November 2003 IPA report.

753. As discussed below, (findings for 2004, *infra*) IPA changed its rating to good, based on the additional scope definition provided by the Carriers, but the rating was premised on the Carriers achieving scope freeze after authorization. Ex. SOA-198 at 31 similar Ex. ATC-258. IPA also had a disclaimer that any scope changes to the project may alter or invalidate the analysis discussed in the report. *Id.* at 2. Clearly, the Carriers were on notice that if there were any changes to the scope they could not rely on the IPA report. The November 2003 IPA report recommended that the Carriers have the "cost estimate validated by one or more of the owner companies' cost engineering departments. Ex. ATC-224 at 6. The record in this case does not indicate whether this was done. The February 2004 IPA report also recommended that the Carriers "reassess the number of labor hours required to complete the project." Ex. ATC-258 at 5. This record does not have any evidence that this was ever done. Ex. SOA-001 at 165. This report also recommended that the Carriers adhere to a "strict no change policy." Ex. SOA-258 at 5. As discussed below, this was never done. Therefore, it is found that the record does not support the Carriers argument that their internal requirements for approval were extensive and demanding.

754. Additionally, the Carriers argue that in 2003 there were multiple cold-eyes or peer reviews done by the Carriers' subject–matter experts, contractors and IPA and Larkspur. Carriers IB 132 (citing Exs. ATC-18 at 31, ATC-21 at 17, ATC-185, ATC-202, ATC-208 at 96-120, ATC-222). The cited exhibits are anecdotal and are not reports from subject-matter experts. The Carriers' statements cannot be corroborated since there is no underlying documentation to any such alleged reviews.[440] Additionally, Larkspur and IPA noted that the project had issues. Thusly, at the time of sanction the Carriers knew that the project needed further study. Their actions were not those of a prudent utility manager.

755. The Carriers argue that Alyeska's operations personnel participated and provided input into the design. Carriers IB 132. The evidence in this case shows the opposite. Alyeska's operations personnel were not timely considered in the planning and execution

[440] *See* discussion above about ATC-27 at 30-31 Gaul's review for Exxon.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

phases. The Carriers' own records indicate that a Program Team led by seconded Owner employees was created to introduce "breakthrough thinking" processes to the project. The team reported directly to the CEO, separate from the Alyeska operations and project organization. Ex. SOA-292 at 3. The Carriers viewed Alyeska's processes as taking more time to get things done and being more expensive. Tr. 4699:14-25. The Carriers wanted to avoid Alyeska's red tape. Tr. 4823:24-4824:2. Additionally, the Carriers' cite the assignment of Veit to work on the SR Team at SNC's offices in Edmonton, to demonstrate that operations was involved in the process. Veit was assigned to Edmonton effective December 1, 2003 and by December 15, 2003, he was approving project drawings as deliverable for preliminary engineering. Exs. ATC-227 and 232. He himself admits that he conducted a "high level review" of the pump station electrification drawings. In addition, he admits that "there remains uncertainties regarding piping tie-in points" that will be worked on and "resolved prior to going into detailed design." Thus, the Carriers did not prove that operations personnel participated on an ongoing basis to provide input into the design. It is found that Veit's was more a *pro forma* type review to move the process along.

756. The Carriers repeatedly argue that they set the industry standards and thus by this mere fact they cannot due any wrong. Carriers IB 136. Consequently, they argue that in order to find lack of prudence the Commission would have to conclude that BP, Conoco and Exxon failed to conduct due diligence "up to the highest levels of those companies" and that none of their analyses were credible. The Commission's test looks at whether the costs in this case are costs which a reasonable utility management would have made in good faith, under the same circumstances and at the relevant point in time. *See New England, supra*. Throughout this decision this is the standard that has been followed. There is no evidence in this record to support the allegation that the Carriers set the industry standard. As a result, this argument is meritless.

757. Moreover, in this case the parent companies were not parties to the proceeding, as a matter of fact the Carriers vehemently argued against discovery against the parent companies. Thusly, their credibility cannot be assessed. However, what can be assessed is what actions the Carriers took or did not take to make the decision to go ahead with the project and with project execution. The documentary evidence in this case (their own evidence) overwhelmingly disfavors the Carriers arguments of prudence. Reviewing the evidence in this case it appears the parent companies relied primarily on the economic analysis provided by the Carriers.[441] This was a superficial process. It is noted that the

[441] For instance, EAG relied on EMPC and review of the funding package and extracts from IPA front-end loading assessment and a brief look at the project execution plan. Exs. ATC-254; 263; 264 and 269 for Exxon. Exs. ATC-251; 253; 255 and 262 for Conoco. Ex. ATC-251 is AFE SO20 package with Cononoco's economic analysis. Exs. ATC-260; 261 and 268 for BP. BP's internal support included the 23 page Decision support package for AFE S020. Ex. ATC-260.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

economic analyses done by the companies are not supported by any underlying documentation. As the evidence in this case demonstrates, at the time the project was sanctioned, engineering had not been completed and thus the scope, costs and savings were not adequately defined. The Carriers knew this and knew they were not following industry standards to adequately sanction a project.

758. As Staff points out, the Carriers contend that their actions are beyond scrutiny because they wanted to reduce O&M expenses by virtue of SR and they had no motivation to spend money unnecessarily. Staff RB 9. "This contention turns decades of Commission and court precedent on its head." *Id.* Again the prudence precedent does not look into motivation behind the decision. As Staff correctly avers, "there is no *mens rea* requirement for a finding of imprudence." *Id.* at 10. However, the Carriers conduct in this case, having repeated failures in following appropriate engineering protocols, ignoring their own experts, rushing a project and then arguing that this is the industry standard makes one wonder what is out there.

759. Anadarko is also correct that the Carrier witnesses who were involved in the decision to proceed and continue with SR were not credible in the defense of those decisions. Anadarko is correct that they based their testimony on "what they knew at the time." However, this is not credible since it ignored all the previous studies done by Alyeska and the comments of Alyeska's senior personnel as well as what they should have known. The Carriers intentionally bypassed Alyeska's management team and its structure and created a separate PMT. The Carriers knew and ignored that a realistic schedule was essential for a successful project. As Merrow points out in his book on large projects, it has been "known within the IPA customer community for many years" that "speed destroys" project outcomes. Ex. AT-267 at 2 and AT-273 at 115. Merrow also identifies "schedule pressure" as dooming more projects than "any other single factor." Exs. AT-268 at 3 and AT-273 at 2. The Carriers knew that SR would have to have "flawless execution" and "zero float" but ignored these facts. Tr. 5806:1-6. Finally, Anadarko is correct that a 22 month schedule for the project was an imprudent beginning for a complex project that required integration of new control systems and new MLUs.

760. Moreover, it is concluded that the Carriers knew best industry practices and chose to ignore them in this case. Therefore, these actions are not the actions of a reasonable utility manager acting in good faith, under the same circumstances and in the relevant point in time. Exhibit SOA-59 at page 2 contains an admission against interests.[442] To wit, this is a funding request for $7 million under AFE S020 for preliminary engineering work. The document states:

[442] The exhibit is not dated. Anadarko asserts in its brief that it was dated February 2003. The document at page 8 has a start date of January 2003. The Joint Chronology Ex. J-2 lists it as January 1, 2003. For purposes of this decision, the January date will be used.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> This project will be managed using Front-End Loading (FEL) methods that the industry recognizes as best practices to reduce overall costs and mitigate financial risk. Preliminary engineering is the next step following the conceptual engineering work that was completed in October 2002.
>
> Preliminary engineering reduces financial risk by eliminating unnecessary scope before the implementation contractors are involved. In addition, the design can be sufficiently developed to enable design reviews by regulators and design professionals ahead of procurement and construction. In summary, FEL reduces uncertainty and increases the probability of success.
>
> The results of this AFE will provide the information to support an overall project decision on pump station electrification and pipeline automation. If the project remains economic, the implementation AFE will be submitted in 4Q'03.

Ex. SOA-59 at 2.

761. The Carriers' bypassing Alyeska had significant consequences. They assumed this risk. As Hisey testified Alyeska is "very focused on safety, operational integrity, reliability, very, very focused on engineering detail, rigor, regulations. They are a very tightly regulated company. They believe they are the most regulated pipeline in the world, if not the top few. So they are highly regulated. Their people are very, very focused on . . . but they are less focused on technical issues and dotting the Is and crossing the Ts. . . the owner companies are big oil companies, big strategic thinking, long-range plan, take huge risks around the world. They drill billion-dollar dry holes. They think of things entirely differently than Alyeska as a pipeline thinks about things." Tr. 2961:2-2962:2. Hisey[443] also testified that the owners are used to taking big risks. That's what they do. Tr. 2961:2-2962:2 and 2976:15-19.

762. The Carriers claim that the report done by Argonne Laboratory (Argonne) in 2003 "confirmed that the reconfiguration strategy proposed for TAPS was 'consistent with current pipeline industry practices' for automation and electrification of pump stations throughout the U.S. and Canada." Carriers IB 93. The "Trans-Alaska Pipeline System Upgrade and Reconfiguration Benchmarking Study" (Ex. ATC-204) done by Argonne in 2003 is not given any weight in this proceeding.[444] The Argonne report was prepared by the Environmental Assessment Division of Argonne Labs. *Id.* at 3. The study compiled findings from surveys of oil pipelines that had electrified their pumping equipment in the

[443] Hisey is uniquely qualified to comment on this. He worked at Alyeska as an employee and as an owner/ownee. Tr. 2961:16-22.

[444] The Carrier's argue that this report should be given substantial weight in this proceeding. Carriers IB 94.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

US and Canada. *Id.* at 45-46. Only one pipeline in the study had replaced gas turbines with electric motors in the last 10 years. *Id.* at 26. The study does not identify the location. The other companies (89%) had converted their pump stations to electric motors more than 25 years ago, except, where there was no electrical power available or where electrical supply was unreliable. *Id.*at 21.

763. Anadarko and the State are correct that this study does not provide support or benchmarks for the Carriers' decision to electrify their pump stations. As a matter of fact, a different conclusion can be reached from this study. The report shows that industry practice was to replace gas turbines with electric motors only where there was electrical power available and where electrical power supplies were reliable. One of the basic design elements of electrification is that self-generation is required due to the unavailability of electric power at PS 1, 3, and 4. Consequently, TAPS falls into the exception identified in the Argonne Report where "there is no electrical power available or where electrical power supplies are unreliable." *Id.* Additionally, the Argonne report did not study why the surveyed pipelines used electric pumps nor did it discuss whether any of the pipelines it studied were located in remote areas away from third-party sources of electricity, or what the costs and benefits of such a conversion would be. Argonne was just a compilation from surveys of oil pipelines that used electrified pumping equipment in the US and Canada and reported which equipment was used. *Id.* at 45-46. It is found that the Argonne study made the Carrier's aware that further study was needed. However, three months later the project was sanctioned.

764. Additionally, the Argonne report was not prepared by oil pipeline experts. It was prepared by the Environmental Assessment Division of Argonne Laboratory, one of the lead authors, John Krummel, is an ecologist rather than a pipeline engineer. Ex. SOA-542 at 32:11-14. As the State points out, the Argonne report does not provide any support for conversion of turbine drives to electric drives as contemplated by SR.

765. The reliability, safety, and maintenance concerns with the untested and complex electrified pumps leads to the conclusion that it may require fewer operators but more maintenance personnel at the electrified pumps. Ex. AT-405 at 8-9.

766. The Carriers estimated that SR would take less time than projects that proposed upgrading only the control systems. However, this is contrary to their own rotating equipment expert. For instance, prior to sanction, DeHaas noted: "that the electrification option is the least standard of any of the concepts. "It requires a mix of equipment and concept at two pump stations, which is more non standard than any other concept, including a hybrid concept." Ex. SOA-284. Moreover, as stated above all the previous automation studies estimated at least 3 to 4 years for completion. Ex. SOA-135 at 52.[445] The Carriers decision to fast-track the project was imprudent. The fast-track schedule

[445] *See also* Ex. SOA-134 at 31 (estimating approximately four years); ATC-108 (estimating approximately 3.5 years; SOA-153 (estimating approximately four years).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

was not justified, was unreasonable and led to the sanction of electrification prior to completion of industry-standard engineering. As the Carriers' witness Barrett testified the accelerated schedule was a significant known risk that the Carriers assumed. "There was significant risk that we would not make the schedule, and there was significant risk that we could have some additional cost, some of which we knew about and some of which - - obviously, in a project like this, there are going to be things that you don't know about." Tr. 5807:7-22. These risks were known at the time. *Id.*[446]

767. The Carriers sanctioned the project knowing PS1 and PS9 scope was not finished (power issues) thus the costs were really not finalized. Ex. SOA-172. Ultimately, the Carriers had to request additional funds to provide internal power generation at these stations (self-generation at PS1 and backup generation at PS9). Exs. ATC-281; 284; 285. *See* discussion below. The State is correct that a prudent manager would have locked in service and price terms with the electric power service provider prior to sanction. As Staff correctly points out, the record supports the conclusion that the Carriers proceeded with SR predicated on predilections and not reasoned decision-making, assessment of alternatives, and giving fair weight to recommendations to wait and/or proceed in a different manner other than the path taken. Staff RB 25.

768. As Staff asserts, in addition to design failures, the Carriers failed to determine two basic components of SR prior to sanction: (1) how the pump stations would get the electricity needed for electrification and (2) how the pump stations would actually accomplish automation. Staff continues that this was consistent with their imprudence in focusing on electrification, and they did not determine the availability of electric power for PS 1 and PS 9. At the time electrification was being considered no power agreements were in place to provide the electric power requirements for PS 1 or PS 9. Staff correctly

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[446] The Carriers argue that the fast-track schedule was a reasonable decision because they accepted a "manageable risk" a decision which is in line with the preference of FERC and the D.C. Circuit to eschew risk-free choices that do not benefit shippers. Citing *Iroquis Gas Transmission Sys., L.P. v. FERC*, 145 F. 3d 398, 401-03 (D.C. Cir. 1998). Carriers RB 61. First, the cited case does not stand for the proposition for which it is cited. Second, based on the facts of this case, the fast track schedule was not a reasonable choice and the risks where not manageable based on the facts they had at the time. At the time the choice was made, the costs had not been developed to a sufficient certainty for a reasonable utility manager to be able to decide that $51 million per year in O& M savings, and avoidance of substantial fire and gas upgrades was going to be more than the "minimal downsides if that schedule was not met." *Id.* They did not have the metrics to make this judgment and the language quoted shows that the metrics they used were not reasonable. Moreover, this record is devoid of any particular instance where the ratepayers benefits of their actions were considered by the Carriers at the time of sanction. The same logic applies to the Carriers justification for parallel construction set forth in their reply brief. Carriers RB 63.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

avers that the Carriers failure to have plans and arrangements in place is emblematic of their imprudence. Exs. ATC-270 and ATC-271 at 2.

769. As Staff correctly asserts, the Carriers: (i) engaged in a rushed and biased comparison of automation alternatives designed to justify a preordained solution; (ii) engaged in insufficient planning and engineering of electrification prior to sanction; (iii) electrification failed to meet the Carriers requirements for approval and should not have been sanctioned; and (iv) the Carriers failed to provide adequate oversight over the project's contractors during the execution phase. Staff RB 37 (citing Ex. SOA-542 at 9-10).

6. What happened in 2004

January 6, 2004

770. Alyeska employee G. Jones, expressed concerns about the SR project. Ex. SOA-281. He suggested some areas for improvement, for instance, he states that "too often it felt like the owners were the client and not enough focus was being given to what a prudent operator would advocate; many times the SR team was pre-disposed to answers that "appeared to best fit very preliminary cost estimates, almost giving the illusion of working the problem backwards … it had the effect of disenfranching (zic) some employees who were being asked for their input;" "Bill is seen as very technically competent, but is using his position power to influence outcomes more to the project team's liking;. .. his loyalties lie principally with the project team vice being a true liaison for the client-operations." *Id.* Further, he states, "[t]here is a inherent bias by the team towards a desired outcome when putting together business cases …vice remaining more neutral. As Jim has noted, the team has yet to get one right on operations matters. When you look at the team makeup, they are too quick to get invested in a desired outcome and fail to accurately describe the downside and operational risks." *Id.* at 2.

January 12, 2004 - Second Larkspur Report

771. A January 12, 2004, letter from Larkspur notes the potential cost impact listed in the report totals $23 million dollars. Ex. SOA-223. It concludes the accuracy level is not within the range stated of +/-15%. *Id.* at 2. It concludes the same way, with major concerns that the project as currently designed could be built for the current estimate value. "Although the current scope of the project is changing rapidly since the original estimate was published, many if not all of the potential cost issues stated in this report still apply to the project. *Id.* at 14. Although in both letters Larkspur requested a meeting, there is no evidence in this record that the meeting ever took place. The only discernible difference between the two reports is the quantification of the changes Larkspur is estimating. *See Id.* at 4. (Table of Estimate Review Results).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

January 14, 2004

772. In January 14, 2004, Al Bolea expressed concern and urgency in resolving the commercial terms for power sharing with PBU for PS1. He states: "If the commercial terms are not agreed (or somehow ring-fenced) for power sharing with PBU, I have told the other TAPS owners that will have no option but to strip PS1 out of the economics for the early March approval. Only three stations would be electrified. We could not commit to an investment at PS1 with a key commercial term left open. I think the bosses in London would give you and I a good bashing if we added another commercial lever to our partners." Ex. SOA-8.

Project Summary

773. A project summary notebook dated January 14, 2004, is Ex. SOA-463. The recommendation is electrification of pumps 1, 3, 4 and 9. The scope includes injection pump upgrades and automation of PS 5; fire and gas systems upgrades and limited automation of PS 7; complete work at rampdown stations 2, 6, 8, 10 and 12 (this includes: replacement of communication and control systems appropriate with minimal data gathering equipment to support the leak detection system; appropriate power supply; minimal security (intrusion alarm and fence); installation of control and communication modules at pump stations. The synergies of the project are that the oil spill contingency plan can be regionalized (reducing field staff); operation technician functions will be eliminated and this will enhance reduced building infrastructure, services and field-based support groups; allows for centralized dispatch for scheduled maintenance; security system upgrades, made possible by telecommunication improvements, allow for reduced physical presence of security personnel at remote facilities due to substitution of technology for people. *Id.* at 14. The document states that direct turbine drives a variation of the electrification option using gas turbines instead of electric motors was also considered. This option was deemed more mechanically complex and slightly less reliable. *Id.* at 7 and 20.

Email January 19, 2004

774. On January 19, 2004, P. Dowling sent an email expressing concerns with the SR project and the selection of SNC Lavlin to execute the project. This was in response to an email (from V. Schwantes) which stated that the proposed work for SR benchmarks well against other similar projects. P. Dowling states:

> The way I read the data, it doesn't tell me that we compare well with the benchmarks like they say it does. In theory SNC Lavlin has learned from their previous projects and therefore can incorporate those learning's into our project. That's why we are presumably using them. Where are the Learning Curve gains? The data shows that we have fewer pump stations and fewer pumps than the other two projects and yet Lavlin's management costs are higher. … Maybe the Corridor project was a train wreck! The

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> bottom line is – if SNC has learned anything from their previous projects then the TAPS project should be BETTER than the other two on all measures. The way I read the data the TAPS project is either the worst or close to the worst in all measures.

Ex. SOA-221.

EAG Review of SR January 20, 2004

775. The basis for the evaluation conducted by Gaul, (Exxon's management group) was a three hour discussion with the EM "Project Manager", the Project Executive and EMPC Regional Coordinator on January 20, 2004. He reviewed the funding package and extracts from IPA Front-End Loading Assessment report and a brief look at the Project Execution Plan. Ex. SOA-258 at 2. In the general observations he noted that the brownfield component of the work appears moderate to low. There is minimal integration between the new facilities and the existing facilities. *Id.* SNC Lavlin has been selected as the contractor for engineering and to provide management services including quality assurance at key contractor and vendor sites. Seventy percent of the key equipment has been ordered or is in final negotiations.

776. Gaul concluded that the "contingency appears low relative to current level of project definition." Dealing with the schedule he states that it "includes no explicit float." In terms of project management he concludes that the project team does not have a well-established, structured project management system and some work processes did not appear to be well established. *Id.* at 3. Concerning timing of full funding the document states, although "preliminary engineering has been performed, full funding is progressing before detailed design has progressed significantly. Major fabrication contracts have not yet been tendered, leaving a higher than normal degree of uncertainty in the estimates at funding." *Id.* at 4.

Conoco TAPS Pipeline Recapitalization - January 22, 2004

777. This Conoco document has some metrics for the base case and expected case and ascribes NPV to both. Ex. ATC-255 at 2. It also shows sensitivities for major maintenance savings totaling $117 base (in 20 years)[447] and O&M savings of $14MMyr base for an investment of $58 MM base. At page 3 the document states that there is a recommendation to sanction "recapitalization with throughput of 1.12 MMBD capacity "scalable." The document also states that preliminary engineering is complete and that there is Owner and Stakeholder alignment. Major maintenance savings are ascribed to fire system upgrades $6 million, station control panels $4 million, RGV control system $2 million, maintenance on 77 out-of-service buildings, unidentified approximately $33 million (over 20 years) (savings from reduction in equipment, infrastructure, plant

[447] *Id.* at 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

footprint). *Id.* at 7. Value sensitivities project a loss of part or all of a bonus depreciation for a schedule delay from 4Q or '05 to 1Q '06. *Id.* at 8. With a one year delay you would have to defer cost reductions. *Id.* The document mentions that additional power generation is required for PS 1 power requirements. This will have a small reduction in O&M savings. The value sensitivities were not included in stochastic (probabilistic) analysis or metrics. Staff reductions total 285 (149 contractors and 136 Alyeska). *Id.* at 12. Note that "after project" "PS 3 and 4 are unmanned, supported from Galbraith Maintenance & Response Base" with a total of 54 people, on shift 27 people." *Id.*

778. On page 14, the exhibit shows Conoco's business cash margin change "Project Incremental CPAI (Producer) CF/Net Barrel. *Id.* at 14. The document also shows the number of pumps vs. capacity. *Id.* at 15. The assumption listed on page 16 states that additional power generation costs at CPS or GVEA are not included.

Prospective Evaluation of the SR Project – February 2004

779. IPA collected data in an interview on January 14, 2004, and issued a final report on the project in February 2004.[448] Ex. ATC-258. The first thing of note, in the preface is the disclaimer that "any scope changes to the project may alter or invalidate the analysis results discussed in this report." *Id.* at 2. IPA found that based on the data collected the FEL is in the Good range.[449] *Id.* at 3. A project in this range had a good chance of completion within budget and on time. *Id.* Although the report stated that engineering definition and project execution had reached the "Best Practical" level, it noted that the level of definition in the site-specific factors shows some gaps. It states that the plot plans are not complete, there is no final field verification of the tie-in points or of the plot plans versus the soil contamination location maps. "The soil definition is based on existing soil reports that date from around 1970" and a "third party interpolated the existing data to draw preliminary conclusions on soil conditions." *Id.* at 3. IPA states a "remaining risk is that of significant changes to the design after the start of execution. Late design changes lead to cost growth and schedule slip. In order to maintain current cost and schedule competitiveness, the team should remain aligned on the project objectives and adhere to a strict no-change policy." *Id.*

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[448] The Joint Chronology dates this exhibit to February 1, 2004. Ex. J-2.

[449] The SRP number was 5.0 the industry average is 5.57. Good is below the "best practical range at authorization." *Id.* at 10. "[T]he goal of all project teams at the time of authorization should be to achieve a Best Practical FEL, with an Index of 4.00-4.75, rather than 3.00." IPA states the objective of FEL is to gain a detailed understanding of the project to minimize the number of changes during later phases of project execution. "FEL proceeds until the "right" project is selected and is not finished until a full design-basis package has been completed. FEL includes project definition and process design, such as the development of flowsheets and the first set of piping and instrumentation diagrams (P&IDs)." *Id.* at 10.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

780. The report continues as follows: "[d]ue to the unique nature of the project, a Cost Effectiveness Index (CEI) cannot be provided. IPA does not possess a model that can credibly benchmark costs for projects like the SRP Project."[450] *Id.* "Instead of performing a CEI, IPA performed a cost gap analysis. We compared some key project cost ratios and found that, compared with other similar projects, the construction labor costs were low relative to the amount of materials to be installed. However, the project's overall costs are in line with Industry. The office costs are higher than Industry, but the estimate for field costs is lower than Industry." *Id.* at 3-4. "The estimated field costs are lower than Industry, which is an area of concern because IPA used a lower construction labor rate than the SRP Project assumes to adjust for construction performed in Alaska. In other words, the SRP Project's estimate includes fewer construction labor hours than is typical for the amount of materials installed. In order to ensure that the estimate for field costs is adequate, the team should reassess the amount of construction hours required." *Id.* at 4. The report notes that power at PS 9 will be grid supplied and PSs 3 and 4 will be supplied power by "new gas turbine generators." *Id.*at 7. Note no mention is made of how PS 1 will obtain power. Long-lead equipment procurement has started. *Id.* at 8. "The modular construction work will be executed under a lump-sum contract." *Id.* Twenty percent of the scope work for automation had been completed. *Id.* at 14.

781. The report finds the planned execution duration[451] to be industry average. However, the detailed engineering and construction phases are shorter than industry average. "The short overlap of the engineering and construction phases causes the overall execution duration to be industry average." *Id.* at 4. The large amount of modular construction items is the main driver for the short detail engineering duration. All modules will be engineered and constructed off-site. The construction duration is also shorter than Industry, which can be explained by the extensive use of overtime."[452]

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[450] IPA refers to the project as SRP "Strategic Reconfiguration Project." *Id.*at 2.

[451] "The execution duration is the duration of the combined phases of detailed engineering and construction." *Id.* at 4 n. 3. IPA found that the planned cycle time of 48 months is approximately 30 percent slower than the average of 37 months for similar projects. The reason for this is the longer FEL duration "can be explained by Alyeska's relative inexperience with managing projects of this size, the SRP Projects complicated environmental permitting issues, and the fact that every major decision has to be approved by each of the five owner companies. The latter also drives the 3-month authorization duration." *Id.* at 30.

[452] The 15 month schedule is shorter than the industry average or 12 percent shorter than industry average. According to IPA, for projects with similar characteristics, 50 percent will complete their construction phases within 14-22 months, and 80 percent of projects complete construction within 11 to 27 months. The median in the dataset is 19 months. The IPA schedule models do not include allowance for external factors that

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Id. at 28. According to IPA, the "team expects authorization on February 27, 2004, and has already started the detailed engineering phase. Construction is planned to start on August 15, 2004, and mechanical completion is expected on November 9, 2005. The final startup activities will be completed on January 18, 2006." *Id.* at 4. IPA recommended that the number of labor hours required to complete the project be reassessed. It also recommended that the Carriers "maintain execution discipline and adhere to a strict no-change policy." *Id.* at 5.

Decision Support Package – Sanction February 9, 2004

782. This document points out that electrification of PS 1, 3, 4 and 9 translates "to an annualized Operating & Maintenance cost savings of $44 mm (gross) by 2008 and will allow TAPS to forego more than $114m in expense and $44m Capital (gross) in costly upgrades to the aging Avons, associated facilities and their enclosure buildings over the next 10 years." Ex. ATC-260 at 3. In terms of the history of TAPS the document points out that due to enhanced recovery techniques, revised reserve volumes, and development of new fields, TAPS is now positioned to operate for another 30 years." Ex. ATC-260 at 3. To support this operational commitment, the Owners initiated a redesign of the pump stations and control systems. *Id.*

783. The document states that electrification satisfies the project objectives of reliability, efficiency and cost-versus-savings. Direct drive turbines was the next best alternative but with reduced reliability and savings and increased maintenance. *Id.* at 5.

784. Alaska's role in BP's portfolio is "to provide a stable production base and cash flow to fuel growth elsewhere in the business while improving margins and returns. Driving cost savings in TAPS is a key element in delivering margin improvement of BP's North Slope production." *Id.* at 13. To wit, the document states that electrification "is the single largest driver of pipeline cost improvement and efficiency." *Id.* at 13. With electrification 285 full time positions will be eliminated many of them in the field where pay is premium with annualized expense savings of over $41mm gross by 2007 over Alyeska's 2003 base O&M. *Id.* BP expects "improved wellhead netback prices due to reduced tariffs." *Id.* Thusly, realizing "organizational savings as quickly as possible is leveraging." *Id.* at 17. A one year delay is estimated in the rage of $40 to $60 million unfavorable.

785. On February 10, 2004, there is an Interim Funding Request for AFE S020. Ex. SOA-487. The request if for $36 million to maintain the 2005 startup schedule. It points out that $10 million have already been funded. This was among others, for preliminary engineering. Now there are purchase order placement processes underway and the project is on schedule but long-lead purchase orders have to be executed, this includes the

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may alter schedules, such as scope changes, cash flow restrictions, labor shortages or stoppages, equipment delivery delays, or unusually bad weather. *Id.* at 29.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

mainline pumps, the VFDs, the pump motors, and the turbine generators. *Id.* By March they have to execute the power sharing agreement with GVEA. Approval of the interim funding will allow $21M in accelerated depreciation which could be lost by not having the new electrified stations in service by December 31, 2005. If start up does not occur by 2005, another $16M would need to be spent to upgrade fire and gas systems based on a commitment to the State Fire Marshall to have code issues corrected by December 31, 2005. Further, annual O&M and avoided major maintenance savings would be deferred by a substantial delay in scheduled cutover to the new pumps. "This would cause overall erosion to the economics of the project." *Id.* at 2.

Full AFE Project Funding Approval - February 11, 2004

786. Conoco in its funding approval document uses 285 total employee staff reductions. Ex. ATC-262 at 7. It also is aware that they are still working on power supply for PS1. *Id.* at 11. Further, the alternative to the power supply issue is to install power generation at PS1 or CPS and GPA provides the backup power. *Id.* The document states that Conoco's production position is leveraged, providing highest return to TAPS Owners. *Id.* at 15. Page 17 is a table showing Conoco's cash margin change (project incremental cash flow per net barrel North Slope Production). This considers the affiliate producers economics to sanction the SR project. This shows evidence of affiliate producer consideration. *See also Id.* at 18.

787. Flood testified that for their analysis they used the numbers provided by the project team. Tr. 5311:14-20. Further, Meg Yaege admitted Conoco relied on project team figures since no one at Conoco could test them. Tr. 4767:8-16.

Sanction Memorandum- February 16, 2004

788. This document is the request by the Alaska Business Unit Mid-stream Alaska Sanction memorandum. The document starts by stating that the Business Unit "requests funding to rebuild and automate four TAPS pump stations by replacing 25 year old direct drive turbine pumps with high efficiency turbine electrical generators and electrical pumps (Electrification). Among other things, the document states that "[t]he resulting automation provides an opportunity for a step-change reduction of 285 full-time positions…" Ex. ATC-261. Further, it states that Alaska's role in BP's portfolio is to provide a stable production base and cash flow to fuel growth elsewhere in the business while improving margins and returns. Achieving efficiencies in TAPS is a key element in delivering margin improvement for BP's North Slope production. Significant margin improvement has been achieved over the past three years, driven by efficiencies in lifting costs and by improvements in tanker and pipeline transportation costs. TAPS 2003 gross O&M costs are $50m lower than 2002 and $100m (19%) lower relative to 2001 when TAPS transformation initiatives began." *Id.* "Electrification is part of a set of projects within the pipeline transformation program. This program includes amendments to the regulator-approved oil spill plan, SCADA host replacement, backbone communication

20140227-3052 FERC PDF (Unofficial) 02/27/2014

upgrades, other pump/relief station automation upgrades, organizational improvements and regulatory-required lifecycle replacements." *Id.*

789. "One of the enablers of pump station manpower reductions is the new oil spill plan. The new plan creates regional response centers and restages equipment to decrease response time to critical locations." "The SCADA replacement and communication upgrades have been approved and are in progress. . . The remaining automation upgrades for ramped-down and relief stations are independent of the decisions regarding Electrification." *Id.*

790. It asserts it is estimated "the combination of new, highly efficient turbines, lower throughput, and electrical utility purchases" reduce "total emissions associated with the TAPS pipeline by 50% or 400,000 tonnes CO2 equivalent annually by 2007." *Id.* There was an assumption of self generation at PS1 "which burdens the project with an incremental net $4mm capex." *Id.*

791. Of note is the following statement concerning regulatory risks: "[a]dditionally, BP has prepared a legislative solution in case the RCA seeks to intervene. Should the RCA move to disallow Electrification cost recovery on intrastate shipments, such costs would be rolled over to our interstate tariff for recovery hence there should be minimal impact to value." *Id.* at 2. Further, "[a]chieving sustainable savings from manpower reductions requires executive will. Given our governance role through the Owners Committee, BP is well positioned to ensure the proper focus and incentives are in place to assure delivery." *Id.*

792. The document points out that "sanction requires the affirmative vote of three or more parties with 66.67% (e.g. BP, XOM & CP or BP, one major, and one minor – minimum). ConocoPhillips approved this project on February 3, 2004. ExxonMobil and Unocal have both informally conveyed their intention to authorize Electrification." *Id.* at 3.

793. Salient is the fact that there is no management of change plan. To wit, "We do not have a robust transition plan in place today. However, Alyeska has appointed a senior leader with single point accountability to create a comprehensive MOC plan." *Id.* at 3.

794. What is troubling about this document is that the economic analysis involves the production entity. For instance, "BP value is manifested in improved wellhead netback prices due to reduced tariffs $68m … and is supplemented slightly by $8m in the pipeline company." Ex. ATC-261. The table financial impact shows the tariff decreasing. *Id.* at 2. The tariff decreasing is also an economic analysis involving the affiliate producers. The regulated entity should not be considering the benefits to the affiliate producers in order to determine whether to improve the pipeline if they are indeed independent companies. Again, this is another document showing that the relationships of these entities are as one, they are totally integrated.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

795. Moreover, the document shows that the Carriers were in favor of the project even though significant issues still had not been resolved, such as power for PS1 and management of change processes. In addition, the underlying numbers were not questioned. *Id.*

AFE Approvals

796. BP Pipelines approved the project on February 24, 2004. Ex. ATC-265. Exxon (Ex. ATC-270) and Conoco approved on March 15, 2004. Ex. ATC-271. Conoco notes the fact that power for PS9 has not been finalized. Moreover, this document states that the scope of PS1 has not been finalized. Ex. ATC-271 at 2. Thus, they approved the project with significant elements, the scope of PS1 and the power for PS9 not finalized.

797. On March 1, 2004, Alyeska (as agent for the Owners) and SNC-Lavalin Constructors, signed a contract for detailed engineering, procurement and construction management services. Ex. ATC-267.

Project Execution

April 5, 2004

798. Within weeks from sanction, there is an email from C. Hatley, Exxon, discussing turbine generator selection. He summarizes owners concerns about a white paper on turbine generator selection. Ex. SOA-290 at 2. There is a discussion on spare parts and training required to maintain different turbines. It is inferred that a turbine recommendation different from the studies was proposed. There is concern about Nox and regulatory restrictions. *Id.* There is a suggestion to revisit the general considerations and tradeoff for two identical turbines vs. two different size turbines. Further, the email states that "our discussions on this issue highlight the need for a MOC process to enhance the potential for a successful project." Project impacts resulting from a change should be assessed, for instance, what is the schedule implication, especially the schedule delay, cost impacts, savings, resulting from Alyeska's recommendation to make this turbine change. *Id.* at 3.

799. The email ends with the following language: "[d]ue to the magnitude and tight timeline" of the TAPS SR project "(including the cost implications of delayed start-up), scope changes should be rigorously managed to avoid scope creep and project delay. Therefore, some restriction on scope changes (i.e. only allowable for safety or environmental issues) could be considered." *Id.* at 3-4.

Email April 30, 2004

800. In an email dated April 30, 2004, Al Bolea apologizes to D. Wright and J. Barrett for Owners' indecisiveness. Further he states that "he does not see a clear way forward. My intuition is that we will end up deferring PS1 electrification or eliminating it entirely. To be candid it always was marginal for BP and it's not going to take us much to back

20140227-3052 FERC PDF (Unofficial) 02/27/2014

away from it. I would suggest that you begin thinking about a plan that does not include PS1 electrification." Ex. SOA-26. This is in relation to the power contract for PS 1.

May 28, 2004

801. The JPO closes Phase One portion of the review process, "allowing us to move on to reviewing and approving Notice to Proceed applications…" Ex. ATC-276. Of note the JPO states: closing "the review of the Preliminary Design Submissions does not eliminate the issues previously identified…" *Id.* at 2.

June 16-17, 2004

802. In June 16-17, 2004, the Technical Oversight Group (TOG) writes that PS 1 and PS 9 should have been critical issues and both have impacted costs and PS 1 in addition has impacted the schedule. Ex. SOA-295. There are notes and some are very interesting. For instance, one of the entries states now "we have better definition of what is in "TAPS SR"; which is everything except VMT SR,…" In addition, the notes reflect that they need to discuss MOC process. Ex. SOA-295. Further, there is a note concerning the status of PS7. Trying to figure out what is happening with PS 7 "Not an issue, PMT understands "shut down PS-7" and intends to close S027 and supplement S028(rampdown stations). *Id.* at 2. An interesting entry states: "[e]ngineering doing power studies instead of getting Project's deliverables out the door to Procurement, etc." *Id.* Concerning contingency, the notes reflect that the contingency was established by risk analysis to arrive at P90, but the owners demanded P50, so the contingency was decreased by $4 million to $12 million on AFE S020. *Id.* Further it notes, "Unknown-unknowns" such as PS-1 power supply alternatives are scope change & supplement; not contingency (TOG agrees). *Id.*

803. In terms of scope items still in flux it lists PS 1 power supply and its impact on the schedule; retained buildings and fire marshal requirements; "due to slower than expected engineering and some equipment delays" field activities have been delayed from 2004 to 2005. *Id.* at 3. Finally, the document states that some of the TOG individuals are on the "not train wrecks" review June 29 until July 2. *Id.*

Email June 18, 2004

804. In a June 18, 2004, status report (email) I. Livett states that detail engineering is approximately 18% complete and services are about 7% behind schedule. Ex. SOA-7. SNC Project Manager and Construction Management team toured the pipeline last week. The long lead material procurement continues. The report states: "[f]ollowing a schedule review meeting in Edmonton, mechanical completion at PS 5 and start up of new generation will slip into 2005. This is primarily driven by engineering being behind schedule, critical material deliveries being longer than originally anticipated and the need to avoid outside construction work in the middle of winter." *Id.* Concerning PS 1 the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

report states that "[t]he failure to secure a power agreement for pump station PS1 continues to significantly impact the engineering and procurement effort. *Id.*

805. In a Pipeline Mitigations Options List a number of actions are listed with the consequences/risks. Ex. SOA-215.[453] One of the options listed is not approving supplemental in April. This would derail the entire MSA transformation strategy. There would be $30 m gross liquidated damages to GVEA take or pay and severe negative consequences. To wit, $140m regret costs, $150m avoided major maintenance costs reintroduced, $50m gross Opex back into system, increased short term costs for contract labor (April staff reductions), lifecycle replacement tied to Electrification…BP loss of reputation in Alaska, Congressional action possible, how do we operate the pipeline that is half finished, pilings in place, modules constructed. *Id.*

806. The exhibit also states in option 2: "replace SNC Lavelin as project management contractor." "No track record of delivery in artic conditions from this contractor." Ex. SOA-215.

July 2004

807. SNC wrote a letter on July 16, 2004. In this letter SNC expresses "serious concerns" regarding the change that has occurred in the last few months and the risks to SNC. It states that through the freeze meetings in April, May and June and the recent Operations and Maintenance review of late June and the addition of the new power generation at PS 1, there have been a large volume of change notices. Additionally, there have been a number of design issues such as the pump station recirculation piping, change to smart actuators and the replacement of hydraulic skids and purchase of new actuators. In addition, there has been an increased workload due to the NTP process that is required by the pipeline regulators and changes to execution strategies due to cold steel delivery that have significantly impacted the project's ability to make progress. As a result, there are concerns about meeting both the schedule and cost targets. Ex. SOA-199. They estimate they are out of budget by approximately "$37 MM with approximately $17 MM for out of scope changes." *Id.* at 2. It points out that with "the number of changes that have occurred" SNC has not been able to present changes fast enough to keep current with the design basis. SNC recommends certain steps to be taken immediately including "no further changes made to the scope of work unless they present a safety or code violation." *Id.*

Project Review

808. In a project review meeting on July 28, 2004, pipeline reconfiguration was discussed. The original scope for AFE S020 was described as: "21 MW Tie-line to Prudhoe Bay, 2 (60%) Turbine/Generators at PS 3 and 4, GVEA grid power @ PS9, 3

[453] This exhibit is dated by the chronology Ex. J-2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Pumps/Motor/VFD sets at PS 1, 3, 4 and 9, Upgrade/Replace MCCs and power distribution, Control & Communications modules with new SCP, automate remaining facilities, Numerous buildings taken out of service/cold." Ex. ATC-278 at 5. A power supply contract was signed with GVEA on May 24, 2004 which made it still on schedule for power delivery to PS 9 by October 2005. *Id.* at 16. The project team had recommended Cyclone/Tempest combination at PS3 and PS 4 but the owners requested Cyclone/Cyclone combination for standardization and additional power. This is $2 million greater than the project recommendation and introduces operational restrictions by reducing the turndown flexibility due to high CO emissions at low temperature and low load. *Id.* at 21. The power agreement between Prudhoe Bay and Alaska was signed in July 2004, but limited continuous power to 3 MW which moved the PS1 completion to the second quarter of 2006 due to scope changes (self-generation). *Id.* at 22. The slide states "permitting and construction schedules are very tight." *Id.* They have spent $52 million (excluding the PS1 cyclone) on equipment. *Id.* at 24. They anticipate upward cost pressure due to commodity price increases, fabrication and construction labor rates and higher logistic costs. *Id.* At this point in time they are having issues with PS 4 due to failed hydrotests of prefabricated pipe spools in fabrication shop (excessive flange rotation). *Id.* at 25.

809. Pump station 5 has been delayed due to scope changes and late engineering, due to building code and lifecycle upgrade requirements. *Id.* at 27. "Second quarter start-up for PS 5 fits with latest SCADA schedule." *Id.* For this pump they are going to need an additional power generation module due to emission restrictions.

810. The original plan was to have PS7 operational through 2013. *Id.* at 30. However, the current decision is to shut it down by December 31, 2005. *Id.* at 31. The rampdown of this PS will be completed by end of 2006. SR to install control, security, and communication upgrades. No-on site personnel after 2006. The remaining facilities and equipment: DRA injection, control module, communications and power generation, OSCP building, warm storage building and bull rail, crude tank and cold restart kit. *Id.*

Supplement I to AFE S020- August 12, 2004

811. Supplement I to AFE S020 was for funding up to $270,423,000. The purpose of the funding is to install new power generation at PS1 as a result of a power sales agreement between APSC and the Prudhoe Bay owners and to fund stipulations of the power sales agreement between Golden Valley Association (GEVA) to provide high voltage power to PS9. Ex. ATC-279. At PS 1 Alyeska will install 18 MW of power by two turbine generators (13 MW Cyclone and a 5 MW machine being sourced). This moved the target date for PS 1 to 2006. Additionally, the costs for the second generator are unknown. *Id.* at 3.

812. The original option for power supply to PS 1 was a power sales agreement with Prudhoe Bay Unit (PBU) for 21 MW by a tie-line to PBU power distribution system. This was the alternative at the time of the original sanction and was pursued for a year

20140227-3052 FERC PDF (Unofficial) 02/27/2014

with PBU during preliminary engineering, past project sanction and well into detail engineering. *Id.* at 4. Ultimately these negotiations failed. The assumption for PS 9 at the time of sanction was $10.8 million for SVC would be financed over 18 years at 10% interest. The contract with GEVA calls for $5.37 million for extending transmission lines to PS 9 and Static Var Compensation. Thus, the agreement has better economics than the assumption in the AFE. *Id.* at 4.

813. The incremental annual O&M cost associated with power generation at PS 1 is assumed to be $100,000. The self-generation at PS 1 added capital costs to the project. *Id.* at 5. The delay in completion of PS1 will affect the timing of the savings for both direct savings and support costs savings attributed to PS1.

September 1, 2004

814. In September 1, 2004 M. Tudor from Exxon is alarmed about cost escalation. Ex. SOA-259. He states the costs at Gate 2 were $234-242 at Gate 3 $279 EM approved $320 (with $25M [?] added contingency). The current outlook $314-345M. *Id.* He states "cost escalation in the order of 30-45% in less than 18 months doesn't result in much confidence that future outlooks will be below the EM approved amount. And all this from a project that was practically on life-support when it was approved." Ex. SOA-259. He goes on to state that he wants to better understand: "what has been proactively done to date to manage the scope and total cost of the project? *Id.* *See* Tr. 5045-46:6.

September 3, 2004

815. On September 3, 2004, C. Hatley by email to D. Ahrens and J. Barrett, states that "SR isn't considered "very robust" within EM. He further states "that there is a significant disconnect between EM and the PL (Pipeline) SR PMT as to the economic viability of the project, with any further scope additions coming close to driving the project over the edge." Ex. SOA-324.

Conoco Approval of Supplement I

816. On September 9, 2004 Conoco approves supplement 1. Ex. ATC-281.

Email September 13, 2004

817. C. Hatley writes another email on September 13, 2004, dealing with among others issues SR. The list of problems includes the following: the chief engineering contractor (SNC Lavalin) has fallen behind schedule on engineering work. "The main issue with delays in engineering design is that SNC won't be able to complete sufficient design work to properly develop lump-sum bid packages for much of the on-site construction work (alternative is time & materials construction which would likely be more expensive)." Ex. ATC-282. Further, the email states that there are no Alyeska project

20140227-3052 FERC PDF (Unofficial) 02/27/2014

team members providing direct oversight in SNC's offices in Edmonton Canada. "Direct oversight is necessary to prevent scope creep and to ensure that SNC remains on whatever "Recovery Plan" is agreed to." *Id.*

818. Additionally, the email goes on to state that "Alyeska has failed to fix the project scope to that originally approved by the TAPS Owners, so scope creep is eating into project resources." *Id.* In addition, the email states that as a result of incorrect assumptions, additional work is required to obtain the originally advertised benefits. *Id.* "Alyeska is on the verge of requesting an additional $8M (gross) for this effort which allows them to recover the original benefits as well as obtain additional benefits. . . there should have been a management of change generated…" *Id.* Alyeska is working on evaluating the potential reconfiguration of PS 1 metering equipment which was not part of the original scope. *Id.*

819. The email further asserts that the project assumed no work for the gas pipeline. However, design engineering identified that gas pressure to PS 1, 3, and 4 at times are less than that required for the gas turbines. *Id.* at 2. Additional life cycle replacements were required when the State Fire Marshall ruled against Alyeska's plan for various pump station buildings (which one would be idled without new fire detection equipment). "There has been significant "cost inflation" in construction work to be performed at the pipeline stations by Alyeska's Projects Group …" An example provided is the cost estimates for tie-ins have increased by $6M (gross). "There is some concern that portions of the project are being over-designed, resulting in additional cost (i.e. pilings everywhere, even under equipment that has been successfully installed/operated in the past w/o pilings)." *Id.*

820. A number of recommendations were made such as placing a team member in Edmonton to monitor SNC's progress, fix design scope to what was approved by the TAPS Owners in the first quarter of 2004 and follow MOC process. *Id.*[454]

Exxon and BP Approval of Supplement I

821. Exxon approves supplement 1 on September 20, 2004 with caveats. To wit, "This approval is made with the expectation that Alyeska will develop and follow a specific plan to maintain and control project scope and costs, including the implementation of an immediate project scope freeze. EMPCO is very concerned by the scope and cost growth exhibited by this project since Gate 2 and by the perceived lack of adherence to best practices in terms of management of change." Ex. ATC-284. In its approval BP notes

[454] *See also* Ex. SOA-358, Memo from C. Hatley to Tudor dated September 20, 2004. In the Memo he again states that Alyeska has to lock the project scope "based upon the Project Summary (Project Manual compiled by the PMT). No scope changes should be made without the appropriate Management of Change document/approval." *Id.* at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

that a $1.7M increase is associated with extended project management costs due to delays. Ex. ATC-285.

September 22, 2004

822. Scope creep continued to plague the project. An email dated September 22, 2004, states that the SIPPS sub-project has been estimated to cost an additional $3.2 million (+/- 25%) over what was in the preliminary engineering in 2003. "SNC is preparing a change notice to capture these costs. They will be funded out of contingency in S020." Ex. SOA-464 at 4.

823. Evidence in the record shows that the owners may have funded certain things under separate AFE so the action would not be deemed additional scope creep for SR. For instance, in September 22, 2004 D. Ahrens writes "John is going to be proposing the idea of funding SIPPS upgrade under a separate AFE, rather than attempting to fund out of S020 contingency. The Project Team considers this work a "must do", and we don't want our request for a separate AFE to be considered another example of "scope creep." Ex. SOA-464 at 3.

October 17, 2004

824. On October 17, 2004 K. Hobeiche writes an email about the MOC. In essence he reiterates that the MOC being followed is in "direct conflict with the wishes of the Owners." Ex. SOA-460. The Owners ordered a "complete freeze on the SR scope of work and wished to see no more scope growth unless it's a direct result of Safety or Regulatory requirements." He states that the Project Team is to "focus all their energy on approved AFE scope, produce necessary engineering packages that support the long lead procurement and produce the "lump sum" construction bid packages." *Id.* The email states that John (Barrett) and Dennis (Ahrens) "seem to agree with the "no change in scope policy."" *Id.*

825. Significantly, the email notes, that there is a schedule recovery plan in place since they are behind schedule and have added 24 staff and 12% overall overtime and this is to continue until the end of detailed design in February 2005. *Id.* at 1-2. "The bottleneck has now moved to Procurement, who are awaiting Engineering to release various design packages." *Id.* at 2. "Critical task is to get the smaller major equipment on order that will go inside the various modules, so that this information can be included in the module RFQs." *Id.* The PS 4 road modification upgrade was not delivered as promised field "workers are being left idle in the field" due to permitting issues." *Id.* "The oil spill contingency plan was approved but with numerous conditions." *Id.*

826. The email also points out that they are having problems with motor vibration. *Id.* Additionally, that the Safety Integrity Pressure Protection System scope and cost have grown since preliminary design. This will have an impact on the schedule. *Id.* The document indicates they are still working on the 5MW unit for PS 1. At this point in

20140227-3052 FERC PDF (Unofficial) 02/27/2014

time, "cost has not been sacrificed to preserve schedule." *Id.* at 3. However, the WIP process is being upgraded since it does not "currently reflect commitments made on large equipment orders." In addition, the "SCADA Host FAT 3 wks behind schedule." Moreover, Barrett and Ahrens were again advised that "continuous high-level PMT presence was critical in the next few months and is required at SNC-Lavalin until schedule control was gooded. PMT advised that since TOG had first raised issue (Aug mtg), that Livett/OFarrell had been in back-to-back rotation." *Id.*

827. Thus, it can be seen that after starting construction they are still working on design engineering and have not frozen the scope of either electrification or automation. They are already behind schedule and throwing more money into the mix so as to not "sacrifice" the schedule. Further, scope is growing and costs are increasing. They have two employees rotating into SNC-Lavalin and having problems with motor vibration. In addition, they are moving costs into other AFEs to hide scope creep.

Year-end 2004

828. The electrification project yielded benefits by allowing the Owners to book additional oil reserves. BP had commissioned a study to examine the minimum hydraulic rate at which the reconfigured pipeline could be operated. Due to the variable speed electric drive pumps, along with anticipated future investments in line heaters (to take place after 2020) it was concluded that the pipeline can be operated at a minimum economic throughput rate of 135 Mbpd.[455] Ex. SOA-11 at 17. Consequently, at year-end 2004, BP booked an additional 63 mmboe of proven-developed reserves on this basis. *Id.* This document also shows that the increased reserves created a depletion, depreciation and amortization improvement of about $0.20/bbl for the Alaska BU. This extended the life of the pipeline to at least 2050. *Id.* If the project is cancelled, these additional reserves will be at risk.[456] *Id. See also Id.* at 4 and 6.

Discussion 2004

829. Sanders testified that the project suffered from not being adequately engineered at the time of sanction. *See also* Exs. SOA-219 at 1-2; SOA-308 and SOA-193 at 13. Further, the Carriers own doucments show that they did not follow their own process to get the project sanctioned. Ex. SOA-542 at 53. C. Sullivan testified that the failure to complete FEL before sanction "led to extensive engineering and design changes, cost increases, schedule delays and project disruption." Ex. SOA-1 at 139:17-19. The State is correct that the Carriers worked backwards and set an unrealistic schedule to accommodate the desired project completion date of 2005 rather than diligently pursuing

[455] Previous studies had indicated a minimum throughput rate of 300 Mbpd using the Avon-driven pumps. *Id.* Ex. SOA 1 at 139:9-10

[456] This is a producer affiliate consideration with no ratepayer benefits.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

preliminary engineering and building a schedule sufficient to perform the work required. J. Barrett who oversaw preliminary engineering testified that he was "handed a target date," the project team put together the schedule to meet the target date, and neither of those changed. Tr. 5664:1-7. Barrett started as program manager on October 7th 2002. Tr. 5659:8-12.[457] The evidence in this case shows that the completion date was set before preliminary engineering was started (Tr. 5661:24-5662:2) and before the project was sanctioned.

830. Sanders' testimony concerning the adequacy of project design at the time of sanction is given significant weight. He testified that there was incomplete and inadequate project design at the time of sanction. As a result, the costs and schedule were incorrect. Ex. SOA-425 at 51-53. The inadequate design was the major cause of the large number of design changes identified by the contractor, as earlier assumptions proved invalid. *Id.* at 52:6-8. Further, it led to changes in detailed design, re-work, and control system design. *Id.* at 52:9-10. It also had an impact on contracting strategy since lump-sum contracts could not be obtained even though lump-sum contracts were factored in the economic justifications of the project. *Id.* at 52:18-53:7.

831. Anadarko correctly argues that the Carriers knew that the 22-month schedule was unachievable based upon the level of engineering that was complete at the time of sanction. As C. Sullivan[458] testified, there were a number of major problems with the schedule at the time of sanction: (1) the project schedule contained only approximately 400 activities, which for a project as large as SR would normally include several thousand activities; (2) the project schedule was not fully resource-loaded, which rendered the schedule ineffective as it does not allow Alyeska to properly assess activity durations when manpower density or shortages of labor issues are foreseen or to properly evaluate both network logic and task durations (resource loading affects logic when too many tasks requiring the same craft or discipline are occurring at the same time, which affects durations because addition or subtraction of resources will directly impact task durations or completion times); and (3) the project schedule did not fully integrate engineering and construction activities, thus possibly preventing a delay in engineering

[457] The Carriers allowed 25 months from hiring the program manager to start-up.

[458] C. Sullivan has worked on over 15 pipeline projects evaluating all phases of project execution, from engineering and design to construction management claims and disputes. He has worked on over 150 industrial facilities, refineries, chemical plants, and other facilities that contain equipment and construction aspects similar to the TAPS pump stations. Ex. SOA-1 at 14. Additionally, Sullivan has worked on many high-profile engineering and construction projects involving refineries, chemical plants, pipelines, petrochemical and industrial facilities, oil and gas projects, as well as commercial buildings. He has experience in all aspects of contract execution, project development, engineering and design, project controls, and project management. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

from being reflected in the downstream construction activities due to the missing and oftentimes faulty scheduling logic. Ex. SOA-1 at 182-183. C. Sullivan states that the most obvious problem was the failure to include sufficient "resource loading" in the schedule.[459] Thus, the Carriers knew that the project was at risk and that "flawless execution" was improbable.

832. The Carriers also claim that the JPO required project schedules to be submitted every 30 days throughout the approval process in an effort to claim that it had developed a schedule that was detailed and resource loaded. Carriers IB 168. However, the JPO was "monitoring for compliance with the contract and the interpretation of what the [the Carriers] are proposing and the contract. Tr. 2601:4-7. The JPO is not responsible or in charge of managing construction of SR. State witness Thompson testified that one reason the JPO requested project schedule updates was to "track it fairly closely to see whether [sic] Alyeska was on a monthly basis." Tr. 2584:6-13. The JPO's did not have the expertise or authority to examine the SR project's schedule to determine whether it was properly resource loaded or contained sufficient detail to execute the project. As Thompson testified, "[w]e're basically permiteers." Tr. 2582:11-12. He also testified that the JPO does not have the engineering resources, expertise or authority to review the substance of the project schedule. Ex. SOA-544 at 12:2-5.

833. In March 2004, the Carriers sanctioned the project at an estimated total cost of $252 million.[460] Ex. SOA-55. Barrett testified that the Carriers knew at the time of sanction that there was uncertainty around the schedule and that it could be extended. Tr. 5849:21-23. He also testified that at sanction, he was "very clear" with the Carriers that engineering was only 30 percent complete and that they would have to expect some changes because of the uncertainty. Tr. 5805:13-25.

834. When they sanctioned the project they had not decided which turbine generators they were going to use, which would make a prudent manager question the cost and savings estimates.[461] *See* discussion above in 2003 for conclusions on lack of prudence before sanction.

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[459] Some activities did contain some resource information, but the vast majority of the remaining procurement, construction, and start-up activities did not contain resource-loading information at sanction. Ex. SOA-275 at 118.

[460] The Carriers reduced the project contingency from $16.5 million to $12.5 million prior to sanction. They did this even though they know there were a lot of uncertainties. Ex. SOA-254 at 6. Yeage testified that uncertainty associated with long-term projecting is always a problem for all the Owners. Tr. 4793:12-18.

[461] If the costs are off the savings are off too.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

835. At sanction the Carriers had not secured a power source for electricity at PS 1. The conceptual plan was for the power to be provided by the Prudhoe Bay unit. Ex. SOA-471. However, Exxon and BP (both unit owners), could not agree on a power sharing agreement for power from the Prudhoe Bay Central Power Station. Ex. SOA-8. This was an important element that impacted engineering and procurement. Ex. SOA-7. This issue was finally resolved in mid-2004 but the solution did not provide all the power needs for PS 1. Consequently, stand-alone power had to be added to the scope of the project for PS 1. Ex. SOA-294 at 58. F. Adams testified that this scope change added costs, delays and engineering changes. Ex. SOA-275 at 68.

836. Yeage testified that this power source issue at PS 1 was a late decision for the project resulting from the "misalignment" of ownership of north slope assets and ownership of TAPS and between sharing of cost and sharing of capital. Tr. 4773; Ex. SOA-375 at 2. The different interests created an issue for the Carriers when it came to making key decisions regarding the SR project. Tr. 4701-04. Be that as it may, this "misalignment" has existed for a long time and it is found cannot excuse their imprudent behavior.

837. The Carriers gloss over the failure to have the issue of power at PS 1 prior to sanction and state that this was accounted for in AFE S020. Carriers IB 53-54. First, AFE S020 on its face does not state that PS 1 lack of power was a part of the decision process. Ex. ATC-237. As the State points out the failure to scope out this issue caused serious problems that manifested themselves soon after execution commenced. In August the Owners Technical Oversight Group was reporting that the failure to finalize the PS 1 power supply caused engineering progress to fall "below curve" because "[e]ngineering [is] doing power studies instead of getting Project's deliverables out the door to Procurement, etc. Ex. SOA-295 at 2. Due to engineering delays, "field activities" were already projected to be delayed an entire year, from 2004 to 2005, "[d]ue to slower than expected engineering and some equipment delays." *Id.* at 3. The Technical Oversight Group also reported that the project team still did not even know such basic facts as what buildings would be retained and what would be needed to be done to meet fire code requirements. *Id.*

838. The Carriers decided to implement the SR Project prior to receiving notices to proceed from the JPO.[462] Ex. SOA-308 at 2. As a result, they assumed the risk that modifications to the project would have to be made based on the JPO's decisions. They also missed the opportunity of having a regulator assist in the scope of the project. Consequently, the staggered NTP for individual scopes of work led to "vast amounts of out of sequence activities and lag time" for construction companies. Ex. SOA-291 at 2. The decision to implement the project prior to receiving NTP's from JPO also contributed to inefficiencies estimated in the millions. Subsequent rework tied up critical engineering resources. Ex. SOA-308 at 2. *See* findings for 2007.

[462] *See* Ex. ATC-276.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

839. The Carriers prematurely started construction without completing the proper level of engineering and project definition. This is contrary to their project management manuals and industry standards. The failure to complete appropriate engineering led to uncontrolled scope changes, management of change problems, increased costs, and schedule delays. These actions were not the actions of a reasonable utility management and the expenses in this case are costs which a reasonable utility management would not have made in good faith, under the same circumstances, and at the relevant point in time. The Carriers actions at this point in time were imprudent and they cannot recover imprudently incurred costs in their rates. As Adams testified the imprudent execution of the project was primarily due to their decision to commence construction prior to completing sufficient engineering. Ex. SOA-275 at 104:20-22.

840. As C. Sullivan testified, the Carriers failed to complete a level of FEL consistent with Alyeska's AMS-003 or industry standards prior to construction in an attempt to meet the unrealistic 2005 deadline. As stated above, the Carriers knew that there were issues with the engineering. Ex. SOA-222 (Larkspur). For instance, in December 2003, Larkspur questioned whether the project as designed could be built for the current estimate value. *Id.* at 13. The evidence shows that there was a lack of detailed design. For instance, Larkspur noted that a "major item missing from the engineering basis was a process/mechanical equipment list. This is an important document because it provides a check list for estimating to make sure that the estimate contains each piece of equipment and the accompanying description provides a basis to insure that the estimator picks up the correct equipment with all ancillaries." *Id.* at 2. Additionally, Larkspur found that SNC's project execution plan "was very general in nature" and should have included "items like module assembly/transportation, who and how the busing to sites would be handled, and any coordination or sharing of resources between the sites." *Id.*

841. Further, considering electrical and instrumentation related costs, Larkspur concluded that the "SNC estimate detail is very general, with footages of wire and cable and quantity of instruments with allowances for terminations and testing…There is a high degree of certainty that additional scope will be required that will not be covered by MTO allowances." *Id.* at 9. Additionally, Larkspur concluded that the engineering did not meet industry standards for construction. "During the review of the estimate quantities, rates, etc., we found significant differences from Alaskan history and for these reasons do not believe the accuracy level of this estimates falls within the stated accuracy range of +15%/-15%." Ex. SOA-222. Later on, during January 2004, Larkspur again expressed concern with the quality of the estimates and stated that it did not agree that the estimates were within 15% accuracy. Ex. SOA-223.

842. As C. Sulllivan testified, lack of sufficient engineering increases the risk that costs will increase during execution due to scope changes and by precluding the implementation of a management of change process. Ex. SOA-1 at 128:16-20. The record in this case shows that that is exactly what happened in this case "because the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

project was not sufficiently defined prior to sanction," the amount and type of work to be done was ill-defined. Therefore, there was substantial post-sanction scope change and re-work required, including re-doing drawings, changing contracting strategies in the middle of the project, and adding new work. . ." Ex. SOA-542 at 80:7-9. This led to "substantial scope growth, delay and cost overruns. . ." *Id.* at 81:2. Right after sanction there was significant scope growth and cost increases prompting Tudor from Exxon to find the scope growth and related cost increases "absolutely alarming." Ex. SOA-259.

843. The Carriers knew that scope had to be controlled in order to control costs. Ex. SOA-290. C. Sullivan testified that the risks of proceeding with inadequate scope include: "incorrect/unrealistic estimates, insufficient design development, design changes, scope growth, schedule delays, as well as engineering and construction rework." Ex. SOA-1 at 200:13-16. C. Sullivan also testified that making numerous changes during project execution, even if the work is necessary, makes that work more expensive. Ex SOA-1 at 185:7-22. Hisey testified that the failure to '[f]reeze scope and stop change" contributed to "additional design change and rework at the field level, as well as a lack of clarity on project progress." Tr. 3543:14-23.

844. As engineering progressed, it became evident that the scope was not adequately defined and in April, May and June 2004, SNC participated in "freeze meetings" to discuss scope. Ex. SOA-199. In July 2004, four months after sanction, SNC stated that due to the large volume of change notices and number of design issues it questioned whether it could meet the original schedule and cost targets. Ex. SOA-199. Tudor also stated that SNC was behind schedule in its completion of design drawings. Ex. ATC-27 at 40.

845. Costs continued to increase. Barrett testified that the cost estimating of SNC was deficient form the beginning. Tr. 5828:22-24. Anadarko correctly points out that the Carriers did not suggest delaying the schedule to allow time for design to be completed and a reliable cost estimate prepared. It is found that a prudent utility manager would have taken steps to finish engineering before proceeding with the project.

846. The project broke ground in August 2004. Shortly thereafter, in September 2004, Tudor noted that "the trend is absolutely alarming . . . Cost escalation in the order of 30-45% in less than 18 months doesn't result in much confidence that future outlooks will be below the Exxon Mobil approved amount." Ex. SOA-259. Another Carrier in the same month complained that, "scope creep is eating into project resources." Ex. SOA-321. Tudor also stated that the trend of the cost growth of the SR Project was "absolutely alarming" and from a project that was practically on "life support" when originally approved. Ex. SOA-259; Tr. 5043:17-5044:14; 5045:21-5046:6. Tudor also testified that the project was economically marginal at preliminary engineering. Tr. 4949:6-13.[463] C.

[463] This is contrary to the Carriers' allegations that the lessons learned documents did not reveal that the project was on life-support prior to sanction. Carriers IB 179.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Hatley of Exxon, also noted on or about September 2004, that any further scope additions from that point forward would come "close to driving the project over the edge." Ex. SOA-324. However, the Carriers did not stop but instead continued with the project and instructed Barrett to proceed with the project notwithstanding the fact that he reported that design engineering was not complete. *See* discussion for 2007 below.

847. Scope changes led to substantial cost increases and schedule delays. Scope growth was a significant driver of costs during project execution. F. Adams testified that "[e]mbarking on a large and complex project without sufficient project planning and definition led to excessive scope and design changes which required rework, delayed and disrupted the Project, and increased the Project's overall cost." Ex. SOA-275 at 98:20-22. The record in this case supports the finding that SNC, Alyeska and the Carriers all agreed that scope changes resulted in delays and cost increases. *See* below, Exs. SOA-456; SOA-65 at 3.

848. It is found that the Carriers did not follow industry practices when they failed to complete sufficient engineering prior to construction. This led to significant scope growth, increased costs and project delays. The Carriers documents demonstrate that scope growth was endemic to the project through its execution within weeks from sanction.

849. In October 2004, the Carriers attempted to freeze the scope by declaring that the scope was frozen but this did not happen. Ex. SOA-460.

850. The State argues that the failure to perform sufficient engineering prior to execution also precluded the adoption of an effective MOC process. An effective MOC process is standard industry practice. This process is crucial to control costs and the schedule. State witness D. Sanders testified that an effective MOC process is needed to control costs and "schedule by coordinating tasks and controlling scope increases." Ex. SOA-542 at 81:6-9.

851. The Carriers themselves knew this to be an important element of the process. The record contains an exhibit which is an Outline Change Control & Management of Contingency which is BP's recommended MOC process. This emphasizes the importance of controlling cost and scheduling changes in order to meet project objectives. Additionally, it points out that a disciplined MOC process is one key aspect of ensuring that changes to a Project are promptly and properly reviewed and controlled. Further, it states that any "deviations from the Project Definition and Scope (Change) can jeopardize the successful outcome of the Project, as uncontrolled changes are one of the most common causes of Project delay and failure. Therefore, the implementation of a formal MOC Process for Major Projects is crucial to the success of such Projects." Ex. SOA-322. Moreover, Alyeska's AMS-003 contains a section on "manage changes." This section requires that changes to scope after the AFE is authorized have to be kept to

20140227-3052 FERC PDF (Unofficial) 02/27/2014

a minimum. Any proposed changes have to be coordinated by the Project Engineer and require the approval of the Project Manager. Ex. SOA-311 at 21.

852. The Carriers knew that the project needed a MOC process to follow during project execution. The EAG Review in January 2004 stated that the "project team does not have a well-established, structured project management system." Ex. SOA-258 at 3. The evidence in this case establishes that the Carriers never implemented an adequate MOC process for the project. *See* findings below for 2005.

853. In December 2004, (four months into construction) SNC updated the budget/forecast number from preliminary engineering which changed the estimate to 30 percent for installation of new facilities and 70 percent work inside existing facilities.[464] Ex. SOA-458. Howitt testified that at sanction the complexity of the work was not understood, "the complexity of working inside the existing pump station, of doing all the hookups, not from module to module, but from module to the existing pump station, was a bad estimate. It was a bad estimate in cost and it was a bad estimate in time." Tr. 7288:24-7289:5. This is evidence of the complete failure of the Carriers to properly define the scope of the project.

854. The truckable modules replaced very little infrastructure at PS 3, 4 and 9 and the fire and gas suppression systems had to be brought into compliance with the fire code at a significant cost.

855. The original scope of the project did not include the fire and gas upgrades. Ex. SOA-487 at 2. The Fire Marshall informed the Carriers that he did not agree with Alyeska's code interpretation and directed it to upgrade the fire and gas protection systems in many of the 77 buildings the PMT had planned on leaving cold or idle. Ex. SOA-60 at 24; SOA-1 at 75. This resulted in significant changes to the project scope and costs.

856. B. Howitt, the only Alyeska employee at conceptual and preliminary engineering, a member of the PMT, was perceived to be influencing outcomes rather than acting as liaison with operations and maintenance. Ex. SOA-281. G. Pomeroy, who led the conceptual studies as well as preparation of the October 2002 decision document was generally regarded as an owners' agent. Ex. SOA-281. An email from G. Jones, recognized that Pomeroy "is prone to rush into the things he is advocating and views opposing views as getting in the way of progress" and that "there is an inherent bias

[464] The project involved a lot more than installing pre-wired truckable pumping modules. Originally, SNC estimated that 90 percent of the work was "General Installation of New Facilities" and 10 percent was "Work for and inside existing facilities." Ex. SOA-458.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

towards a desired outcome when putting together business cases together vice remaining more neutral." Ex. SOA-281 at 1-2.

857. The State is correct that despite the warnings from third party evaluators and despite the fact that there was significant scope growth and costs were escalating, the Carriers continued with the Electrification project to the construction phase and they knew there was not sufficient FEL. Alyeska employees also continued to express concerns regarding the management of the project. For instance, in an email from G. Jones dated January 2004, he discusses the PMT. He states,

> Many times the SR team was pre-disposed to answers that appeared to best fit very preliminary cost estimates, almost giving the illusion of working the problem backwards. By putting pre-conceived "cost" guardrails around the issues, the team effectively was making key decisions that were not theirs to make . . . There is an inherent bias by the team towards a desired outcome when putting together business cases together . . . [versus] remaining more neutral. As Jim has noted, the team has yet to get one right on operations matters. When you look at the team makeup, they are too quick to get invested in a desired outcome and fail to accurately describe the downside and operational risks.

Ex. SOA-281 at 1-2.

This evidence shows that key Alyeska personnel knew the SR team was biased and that their economic justification for the SR project was not neutral, complete or even accurate. Since Alyeska is the Carrier's agent this knowledge is imputed to the Carriers.

858. In the same email he also mentions that B. Howitt is using his position to influence outcomes more to the project team's liking and that people were aware he would not be around to deal with the aftermath. He goes on to state that in "the end, as the operations liaison for SR, I would like Bill to be seen as a strong ally to the operational managers, me and you pushing on things while at the same time protecting operations and ultimately Company interests, as if he was going to have to live with what he is helping create." *Id.* Additionally, he describes Glen as needing to improve his networking with key Alyeska stakeholders and he is not as thorough as he should be when it comes to the "con" side of the equation. He is prone to rush into the things he is advocating and view opposing views as getting in the way of progress. Ex. SOA-281.

859. In January 2004, L. Monthei, VP of Engineering, predicted that the project would cost three times the number that was requested at Project sanctioning. Tr. 3365:20-3366:2. Hisey testified that these concerns were known to everyone. Tr. 3191:3-13. Turnipseed also confirmed that the SR PMT "pushed other departments aside to accomplish their mission." "A poorly conceived design is being further degraded by a lack of commitment to provide support when needed. The pervasive attitude that the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

design is so superior that future human intervention will be a thing of the past, that operators at a keyboard will report problem to an automation team and the automation team will tell maintenance personnel how to respond is absurd." Ex. AT-456 at 3-4. He also stated that when he heard SR was proposed at a cost of $250 he could not figure it out and assumed it would be a less significant proposal that had been made by VECO. However, he then learned that SR was to be more complex. Ex. AT-429 at 7.

860. The failure to consider the suggestions of Alyeska employees resulted in Alyeska being disenfranchised by the process but also the design deliverables were incomplete. Ex. AT-431 at 6-7 (deposition Tr. 84:20-23, 85:1-10, 85:24-86:1).

861. The decision to sanction was based on the analysis of the expected net present value (NPV) and Internal Rate of Return (IRR). NPV is the present value of the expected cash flow streams for the life of the project (includes the investment costs and projected savings) and discounts the cash flows back to a base year. Tr. 1755-56. The IRR is the discount rate at which the present value of expected cash flows of a project is zero. Tr. 1756:8-12. Under the Carrier's standards, a project needs a positive NPV and an IRR of at least 11% or higher to be sanctioned. Ex. SOA-30 at 54.[465] Exxon suggested that for projects like SR "primarily justified on expense savings" it may take a substantially higher ROR to be sanctioned, "in excess of 30%." Ex. SOA-252 at 2 (handwritten notes).

862. The Carriers argue that "reasonable efforts" were made by the Owners to evaluate the economics of the project. Carriers IB 135-36. As established by the evidence, Exxon had a three hour discussion with the "EM Project Manager" to review the funding package for AFE S020, and reviewed extracts from IPA and a brief look at the Project Execution Plan. Ex. ATC-254 at 2 (also at Ex. SOA-258 at 2). It did not examine the underlying data or assumptions in the Project Execution Plan or the assumptions in AFE S020. It did not review the complete IPA Report. Anadarko is correct that no effort was made to have the cost estimate validated by one or more of the companies cost engineering departments as recommended by IPA in November 2003. Ex. SOA-287 at 4. One Owner employee represented that Exxon did not do anything with the figures provided by Alyeska. Ex. SOA-599 at 6:20-25. However, Exxon did recommend a higher contingency of 10 to 12 percent for firm costs and 25 to 30 percent for technical components of commercial uncertainty. Ex. SOA-258 at 3; Ex. SOA-256.

863. The State is correct that the Owners did nothing more than accept the figures provided in the AFE documents and did not scrutinize the underlying assumptions or test

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[465] *See also* ATC-262 at 5; ATC-36 at 38:15 and 42:4-5; ATC-263 at 2; ATC-260 at 14 and ATC-261. BP at exhibits ATC-260 at 14 and 261 used an inflation factor for the cost and savings numbers. Ex. ATC-260 at 13. Carrier witness Dr. Toof did not adjust for inflation when discussing the BP discount rate. Ex. ATC-36 at 35:11-12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the validity of the project justification. State RB 53. The record shows the Owners took the data from the AFE and plugged it into their own ROR and NPV formula. The only revisions were changing the bonus depreciation number and the tax rate. Ex. ATC-269. BP did the same thing. BP accepted the SR PMT's figures and input them into its internal economic model. Ex. ATC-261. Its three page memo on sanction did not challenge any of the SR assumptions on schedule or costs. Ex. ATC-261.

864. The Carriers cite the language in ATC-254 at 2, to challenge the State's contentions. The cited language is that the "EM team responsible for oversight of the project has been heavily engaged with the Alyeska project team during most of the pre-execution phase of the project." There is no explanation in this record as to what this means. Moreover, the fact is that M. Tudor testified that they used the basic cost and savings data provided by the PMT. Ex. ATC-27 at 31:4-7. It then ran this data through their economic evaluation models using various scenarios and sensitivities. *Id.* at 31:7. They added a contingency and extended the project schedule by three months. *Id.*at 31:10-11.

865. The Carriers claim that they added $20 million in engineering tolerance, assumed self-generation at PS 1 and questioned the inputs by analyzing the effect on project economics of various risks, including Owner delay, under-delivery or erosion of savings and capital costs overruns. Carriers RB 72. However, there is no support in the record of how they got to the $20 million in engineering tolerance. If the Carriers are referring to a contingency there is evidence in this record that some months later this contingency was reduced. Ex. SOA-254 at 6. The reason they assumed self-generation at PS 1 is because they did not have a plan in place concerning this at sanction. Further the economic analysis of risks was not challenging the costs or schedule of the project. Thus, the Carriers allegations do not contradict the State's arguments. What is also significant from the BP sanction memorandum is that "[a]voided capital and expense in 2001-2003 totaled $17m net (major maintenance deferrals authorized in anticipation of Electrification)." Ex. ATC-261. This corroborates that a decision to go with electrification had been made since 2001.

866. P. Flood testified at the hearing that Conoco also accepted the figures and put them in their internal formulas. Tr. 5311:14-20. He also testified that the inputs to AFE SO20 "were not correct," and if the inputs to the analysis are incorrect and not challenged, the output of the analysis cannot be trusted; it simply results in "[g]arbage in, garbage out." Tr. 5303:11-17. Ms. Yaege, the Conoco Phillips President, testified that no one in her company understood SR well enough to verify the numbers. Conoco's major project folks made sure all of the right boxes were checked and all the right reviews were done and the estimates were done to the right level." Tr. 4767:8-16. As the State correctly points out, Conoco did not, evaluate substance, evaluate the depth of analysis, or examine any of the figures underlying the information provided in the AFE. State RB 54. The Carriers claim that all the information had already been analyzed by the Owners'

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Pipeline Planning Team as the data was being developed during 2003. Carriers RB 71. There is no evidence in this record to support this statement and the Carriers cite to none.

867. Exxon's review of the project in January 2004, found that the "schedule includes no explicit float" and "[t]he project team does not have a well-established, structured project management system." Ex. SOA-258 at 3. Exxon also stated that "full funding is progressing before detailed design has progressed significantly. Major fabrication contracts have not yet been tendered, leaving a higher than normal degree of uncertainty in the estimates at funding." *Id.* at 4. Thus, the only conclusion that can be reached is that the Carriers knew that they had not followed good industry practices, contrary to the assertions in their briefs. Such actions are not ones a reasonable industry manager would take.

868. The State is correct that if a proper economic analysis of the project had been done, it would have shown that it would not have passed the Carrier's internal funding requirements. Further, if the project had been adequately scoped, with adequate preliminary engineering more realistic cost and savings assumptions would have been obtained, and the conclusion would have been that the project was not economic. D. Hisey testified that if the project was scoped correctly and the engineering done correctly, electrification would not have been considered economic. Tr. 3904:9-16; 3905:1-3 and 7-8.

869. Some of the Carriers knew that the economics of electrification were weak. For instance, M. Tudor (Exxon) stated on September 1, 2004, upon expressing concerns about cost escalation of 30 to 45% in less than 18 months, "that the project was practically on life-support when it was approved." Ex. SOA-259. In January 2004, Gaul an Exxon employee, created a matrix of the SR project. The conclusion was that cost growth of 25 percent or more eroded the economics of the project. Additionally, if the scheduled changed by more than 10-15 percent, the attractiveness of the project would be impacted. Ex. SOA-258 at 7; Tr. 5035:15-17. In September, Hatley indicated that any further scope additions from that point forward would come "close to driving the project over the edge." Ex. SOA-324.

870. The Carriers in their brief quote testimony that characterized the SR project as "a once-in-a-lifetime opportunity fundamentally to improve TAPS operations and cost structure." Carriers IB 124. The State is correct that the Carriers failed to cogently explain why the SR project was a once-in-a-lifetime opportunity in 2003 and why it necessitated a "fast-track" schedule. The State is also correct that the record in this case conclusively demonstrates that the Carriers had opportunities starting as far back as 1994 to make fundamental changes to Alyeska's operations and cost structure through automation, regionalization of oil spill response and maintenance, and resulting staffing reductions. State IB 18-39, 138-47. Additionally, as the State points out there was nothing specific to the electrification option that created these savings – the legacy

20140227-3052 FERC PDF (Unofficial) 02/27/2014

equipment was well-functioning, fit-for-purpose and multiple studies indicated that its control systems could have been enhanced to allow remote operation.

871. It is factually true that the Carriers' documents reflect that the driving forces behind the staffing reductions were (1) the change to a regional oil spill response and maintenance protocols and (2) automation. These two matters are totally independent of electrification. Installing electric motor driven pumps was not the source of staff savings. To wit, BP's Pump Station Electrification Project Sanction Memo stated that one "of the enablers of pump station manpower reductions is the new oil spill plan" and the "resulting automation provides an opportunity for a step-change reduction of 285 full-time positions." Ex. ATC-261. The memo states that new "automation will enable elimination of field-based pipeline operating personnel, reduce support costs and deliver $44 million ($17m BP net) per annum cost reduction by 2008 from current levels." *Id.*

872. G. Shotts, Alyeska Operations and Maintenance Supervisor and Maintenance Transition Lead attributed staff savings to automation, concluding that automation of the pump stations operations will generate a significant reduction in operations personnel, and also shift the personnel locations from the pump stations to the regional facility concept. Ex. SOA-552 at 47.

873. On January 12, 2004, Larkspur wrote that although the scope of the project was changing rapidly since the original estimate, "many if not all of the potential costs issues stated in this report still apply to this project." Ex. SOA-223 at 14. It had concerns that the project as currently designed could be built for the current estimated value. *Id.* Larkspur concluded that there was a high degree of certainty that additional scope will be required." *Id.* at 10. Larkspur requested a meeting with the SR PMT to "fully review and explain our findings that have been briefly outlined in the above report." Ex. SOA-223 at 14. There is no evidence in this record that this meeting took place. Instead, the Carriers removed project contingency from the AFE S020 request. Ex. SOA-255. Additionally, Larkspur was "pulled off the engagement prior to their completion because the team felt that their estimates were too high." Ex. SOA-308. Therefore, it is concluded that the Carriers are not correct when they claim that their decision was derived from processes that had third party review since the record shows that they completely ignored and terminated one such third party reviewer because it identified problems with their engineering.

874. In its February 2004, report IPA noted that "any scope changes to the project may alter or invalidate the analysis results discussed in this report." Ex. SOA-198 at 2 (Ex. ATC-258 at 2). IPA revised its earlier report and changed the rating for the FEL from "poor" to "good." Ex. ATC-258 at 3. However, IPA noted that there was a remaining risk, that of significant changes to the design after the start of execution. "Late design changes lead to cost growth and schedule slip." *Id.* at 3. In addition, the IPA report warned the Carriers that its conclusions did not factor scope changes into its schedule

20140227-3052 FERC PDF (Unofficial) 02/27/2014

analysis. *Id.* at 29. It recommended that the Carriers "[r]eassess the number of labor hours required to complete the project. *Id.* at 5; Ex. SOA-1 at 164-65.

875. The State is correct that the Carriers cannot justify their actions by arguing that IPA reviewed their schedule. Carriers IB 168. The scheduled evaluated by IPA in December 2003 was a Level II schedule which did not define resource requirements. A January 2004, email from P. Dowling of BP, to various members of the SR PMT and Owners Committee members stated, "[a]fter completion of the Level 3 schedule further development of the Execution Plan will better define resource requirements." Thus, at the time of the IPA review the Level 3 schedule had not even been prepared. The Level 3 schedule was the schedule that would provide the necessary resource loading. There is no evidence in this record that a Level 3 schedule was reviewed by IPA or that such a schedule was prepared before sanction or at the time execution started. The State is correct that a Level 3 schedule was not introduced into evidence in this proceeding. Thus, the only inference to be reached is that such a schedule was not developed.

876. The Carriers were also aware that IPA's reports in November and February were based only on one-day meetings. Ex. SOA-287 at 2; Ex. ATC-258 at 2. Anadarko is correct that IPA's report was not an assurance that the plan to install pre-wired truckable modules on the pipeline included the proper scope of the project. Anadarko points out that this was minimal assurance at best. However, it is found that this was no assurance at all. As the State points out the revised IPA report, which was based on interviews conducted in January 2004, did not evaluate substance. Ex. SOA-202 at 11. The State is correct that electrification was plagued by scope changes and therefore, the IPA report cannot be used to validate the project. The report did not study the potential effect of one of the most significant problems with SR or the ill-defined scope. However, the report did identify the risk that was not properly taken into account by the Carriers – the risk of scope changes resulting from inadequate preliminary engineering.

877. The evidence in this case supports the finding that the Carriers did not undertake the actions necessary to address the scope issues. There is evidence that "the Owners had ordered a complete freeze on the SRP scope of work and wished to see no more scope growth unless it is a direct result of Safety or Regulatory requirements. Ex. SOA-460. However, the scope kept growing. It is found that the Carriers actions were not those of a reasonable utility manager. The State is correct that a reasonable manager would have addressed the underlying root cause or the lack of project definition. The Carriers did not do that and instead continued with their fast track schedule.

878. Anadarko is correct that affiliate concerns influenced the decision making of the Carriers. In 2004, BP continued to push the SR project to preserve 63 million barrels of oil booked by its upstream production affiliate (BPXA).[466] Documents show that this

[466] *See* generally, Ex. AT-1 at 26-32 and AT-214 at 24-25 (B. Sullivan detailing booking of reserves).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

was important to BP. For instance, one document characterizes the booking of additional reserves as "THE PRIZE." Ex. AT-14 at 3. An email dated November 5, 2004, between Haines[467] and BPPA President Bolea, states that "[m]omentum is starting to grow around booking more reserves based on an updated view of TAPS minimum achievable rates." Ex. AT-13.

879. Anadarko is correct that affiliate interests influenced the decision. The record shows that the "PMT has been receptive to owner input during pre-execution." Ex. ATC-254 at 4. Exxon noted that the "attractiveness of the project is moderately insensitive to cost growth (e.g. 25% growth would erode economics)." *Id.* at 7. Further, the "attractiveness of project is moderately sensitive to achieving schedule (can tolerate 10-15% growth). It also noted moderate to high potential for the project to negatively impact existing production if not executed well. There would be a "reserves capture" arising from the project. Ex. SOA-258 at 7.

880. Staff argued that Commission precedent mandates, in light of the fact that the owners of TAPS are also the principal shippers on that system, a heightened scrutiny to the Carriers efforts to prove that the project was prudently undertaken. According to Staff, in situations involving affiliate considerations, or other scenarios with the potential for self-dealing, the Commission must apply stricter scrutiny to the second part of the prudence inquiry, and should find that the presence of affiliate considerations, in conjunction with other evidence demonstrating the imprudence of a given expenditure, constitutes a failure by the TAPS Owners to meet this burden. Staff IB 51-52. *See* conclusions below.

881. During 2004, the Carriers failed to supervise or control SNC. They also disregarded the cost overruns arising within the project.

Conclusions 2004

882. The Carriers knew they had unknown-unknowns yet still went ahead with the project instead of waiting until these were "better known." They knew the scope was creeping, they knew costs were escalating and they knew MOC was not an optimal process, yet they continued with the project. The costs nor the savings were changed based on changed economics for PS1. Additional costs issues related to the self-generation scope change were never accounted for in the project economics. A rational and prudent manager would not have started a project based on preliminary engineering. Especially in light of the fact that crucial things such as power for two pump stations had not been established and were dependent on contracts with other entities. Thus, costs were not really pinned down.

[467] A commercial analyst for BPPA.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

883. The Carriers sanctioned[468] electrification without key commercial terms in place, power sources and how this would impact costs. This had a significant impact on the project. As Livetts' letter shows, the failure to "secure a power agreement for pump station PS-1 continues to significantly impact the engineering and procurement effort." Ex. SOA-7; Tr. 5800:10-18. State witness Sanders testified that "launching the Electrification concept without firm definition of fuel costs, connection charges, fees, timing, etc., would not be considered consistent with industry practice when major cash commitments for engineering, long lead pumps and motors and other early equipment orders were made without power supply and interruptibility commitment in hand." Ex. SOA-542 at 58:1-5. This undefined scope significantly impacted the compressed project schedule by delaying engineering and pushing back critical decisions relating to procurement. Ex. SOA-295 at 2, 3; Tr. 5904:11-23; *see also* Tr. 5842:19-5843:5; Ex. SOA-237 at 2.

884. Further, the Owners knew that automation would take longer than two years yet they went ahead and started a project based on a two year schedule. This is in the realm of "what were they thinking?" not only imprudent but illogical. At sanction the Carriers did not have a plan to implement automation of the pump stations which was a major component of SR. In late October 2003, Owner Review found that automation was "based on a vision, not an established plan. Ex. SOA-475 at 8. This is not consistent with the actions of a reasonable utility manager. It was not until early 2007 (well after electrification was to have been completed) that the control system design was adequate to proceed with startup at PS9. Ex. ATC-972 at 5. Thus, the evidence shows that it took approximately three years to develop, test, and implement the automation design for a single pump station. *Id.*

885. The primary goal for SR was economic yet they did not take actions to rework the economic analysis once they knew the project was off course. Yet the question to be asked at a sanction was whether the project was economically justified.

886. Anadarko is correct that the Carriers knew the economics of the SR project were marginal and to capture such speculative and marginal economics is not prudent.[469] Anadarko is also correct that the prudent approach would have demanded a schedule with enough time to properly define the scope of the project, conduct in-depth bench-marking studies, and construct a detailed analysis of project benefits based on reality and not shortcuts such as "factoring" and estimates of unanticipated cost savings. After all these careful steps could a project be prudently evaluated as to reliable cost and savings estimates. As a result, most of the significant problems would have been identified prior to sanction, and consequently this would have allowed the project economics to be reviewed using more realistic cost and savings estimates and identifying a more realistic

[468] Ex. SOA-428 at 6.

[469] Anadarko IB 48.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

schedule for project implementation. Ex. SOA-275 at 67-68. Further, Anadarko is also correct that if industry practices had been followed it would have prevented the "train wreck" that occurred. A train wreck is a term that is used in project management. Tr. 3526:3-4. You are supposed to declare a train wreck to put people on notice that the project is off and that it requires significant large-scale intervention, stop, reassess, redirect. Tr. 3527:25-3528:15; 4037:10-4038:12.

887. The Net Present Value in the October 2002 Decision Document for Electrification (excluding the cost of electricity at PS 1) was $31 million compared to Hybrid. Ex. SOA-28 at 6. As Staff correctly points out, this statement does not mean that electrification was clearly superior to hybrid. M. Tudor (Exxon's President) acknowledge that "[t]his project had a pretty rough ride through our senior management . . . based on 'marginal' return." Ex. SOA-183.

888. Additionally, Anadarko is correct that the Strategic Initiatives Status Report recommended implementation of the initiatives "at selected prototype location(s)." Ex. ATC-108 at 10. A prudent manager would have implemented a pilot project at a single pump station to test out the proposed upgrades in order to assess their effectiveness before completely reconfiguring the pipeline. Ex. SOA-425 at 38. The Carriers decided not to develop a prototype and instead decided to reconfigure all the pump stations at the same time. This conduct was not the act of a reasonable utility manager.

889. BP project principles recognize the importance of acknowledging as the base case the benefits of maintaining the legacy equipment and modifying the control system if needed. Ex. SOA-448 at 12. The Project Principle discussion on the introduction of new technology states, "[s]tandardisation through the re-use or incremental development of previous designs can provide substantial cost, schedule and operability benefits and must be considered for the base case. *Id.* The Carriers did not follow this principle when they chose electrification.

890. The Carriers admit that the project schedule was ambitious and they were aware of the challenging nature of the schedule prior to sanction.[470] The original schedule required completion by December 31, 2005. The Carriers also admit that the legacy equipment was reliable and that SR was not facilities driven but rather driven by economics.[471] At this point in time, a reasonable utility manager would have accurately defined the scope of the project and conducted reasonable studies of the costs and benefits of the project. The Carriers however, rushed into the project allegedly to save operating costs.

[470] Carrier's IB 136, 138.

[471] Carriers IB 114.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

However, one needs to question how any reasonable manager could ascertain costs and savings if the costs are not properly defined.[472]

891. At sanction in March 2004, completion was required in 22 months. The Carriers in their brief assert this is similar to the time frame of Bailey.[473] However, this is not correct, an analysis of Bailey shows that the Carriers schedule is off by one or two years from Bailey. Moreover, they are comparing apples to oranges since Bailey was just for automation. SR included automation and electrification. In their reply brief the Carriers distinguish the amount of pump stations between Bailey and the SR project stating that Bailey involved more pump stations. This is also not accurate since the automation aspects of SR involved the ramp down stations, PS 5 and PS 7, not just solely the "electrified stations." This further supports the unreasonableness of their schedule.[474]

892. The Carriers admit the reason for the schedule was to obtain a one-time tax benefit for property in service by December 31, 2005. This was the driver for the schedule. This is confirmed by contemporaneous documents. Ex. SOA-292 at 3, SOA-166; SOA-240 and SOA-60 at 24. The Carriers arguments[475] to the contrary are not supported by the evidence. The December 31, 2005, was used to negotiate with the Fire Marshall as the target date for satisfying the compliance order. The Carriers contentions that the Fire Marshall's compliance order was a driver is also not supported by the record. Howitt testified that Alyeska routinely negotiated with the Fire Marshall to extend deadlines. Tr. 4357:17-4358:10; Exs. SOA-671-674. Hisey confirmed this. Tr. 3242:1-14; 3245:2-3247:1.

893. Moreover, the Carriers knew the risks of an accelerated schedule. Barrett testified that he was aware that "speed destroys megaprojects." Tr. 5856:7-17. He also testified that "fast tracking (implementation prior to final design) causes significant risk." Tr. 5806:7-10. Barrett testified that he explained the risks to the Carriers, that these risks were significant, and that they assumed the risks. Tr. 5807:7-19.

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[472] At this point in time, they ignored all the previous studies done by Alyeska which showed that electrification had been rejected and favoring partial automation; no other pipeline had installed electric MLUs without access to a reliable electric grid; no other pipeline had ever replaced reliable direct-drive gas turbines MLUs to install electric MLUs; ignored the advice of Alyeska employees concerning the project; and the cost-benefit analysis was conducted by employees known to be pro-project.

[473] Carrier's IB 139-140.

[474] Exs. SOA-62 at 9; ATC-208 at 5.

[475] Carrier's IB 138.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

894. One of the risks of accelerating the project was the lack of time to properly define the scope of the project. This is a fundamental step to estimate the costs. As discussed below, the evidence in this case shows that this is exactly what happened in this case. *See* SOA-63 at 5 discussed below. The scope was poorly defined at sanction. The costs of SR have more than tripled from the original estimate. All this from a project that "was on life support" at sanction. Ex. SOA-259. The Carriers try to justify their actions by stating that scope changes do not establish imprudence at sanction.[476] Anadarko is correct that what happened in this project were not merely "scope changes" but the post-sanction completion of design and engineering finally defining the scope. Anadarko is correct that this was a fundamental defect in project planning and not an implementation issue. It is found that the Carriers actions in this regard were not the actions of a reasonable utility manager. As Sanders testified "project overruns of 300% are not industry standard and most of these cost overruns were entirely foreseeable results of the failures of the TAPS Carriers, Alyeska, and the contractors in the planning and execution of the [SR] project." Ex. SOA-542 at 79:11-15.

895. The Carriers concede that delaying the sanction evaluation to a later point might have been advisable, but claim that this is a perspective based on hindsight. Carriers RB 76. However, as demonstrated this is not correct. They knew they had shortchanged their processes and assumed the risks. Part of the risks they assumed was the regulatory risk that their actions would be found not consistent with those of a reasonable utility manager. The real question in this case is whether the shippers should pay costs when the utility decides to sanction a project before it has finished scoping it or having finished detailed engineering. The Carriers argue that each of their economic analyses recognized the possibility that the project could cost more and take longer than projected and that this risk was part of the economic decision. Carriers RB 76. Consequently, it is found that the Carriers assumed these risks and that they cannot pass these costs to the unaffiliated shippers.

896. The Carriers attempt to support their claims that the scope changes were unforeseeable implementation issues by asserting that the Fire Marshall required the retention of a number of buildings which had been assumed decommissioned or removed.[477] However, this is not correct.[478] As of December 2003, prior to sanction, the

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[476] Carriers IB 145.

[477] Carriers IB 147.

[478] As testified by C. Sullivan, during the original construction of the pipeline, foam insulated metal clad panels were used for the exterior wall of the buildings. This was a code violation, mitigated by agreeing to provide detection and suppression systems in all areas where the wall panels were required by code to have the flame spread rating. This decades old agreement was rediscovered during SR and it became necessary to retain and upgrade several systems that had been slated for removal. Ex. SOA-1 at 75.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

JPO notified the Carriers that the plan to remove 20 percent of the walls and let buildings go cold did not meet the state building code requirements. Ex. ATC-233 at 9. The original scope of the project did not include the fire and gas upgrades. Ex. SOA-487 at 2. The Fire Marshall did not agree with the Carriers interpretation of the fire codes and directed upgrades to the fire and gas protection systems in many of the 77 buildings that were planned to be cold or idle. Ex. SOA-150 at 8, 20, 29, 33; SOA-238 at 1; *see also* Ex. SOA-1 at 75. These new requirements resulted in fundamental changes to the overall project scope. Ex. SOA-238.

897. Additionally, in November 2003, Hinz reported that there were "differing opinions even amongst long-time Alyeska employees concerning the continued use of facilities and the existing fire code governing the fire systems that needed to be in place in those facilities.[479] A small system in one building would require support from another building so it was imperative to ascertain which buildings would remain. Systems included instrument air, refrigeration systems, relief systems, heating systems, etc. Ex. SOA-163 at 6. Thus, the evidence shows that less than three months before sanction, there was no consensus on whether or not electrification would allow the Carriers to remove "most of the existing infrastructure." Ex. SOA-163 at 8. The notes from a meeting of the TAPS Owners' Technical Oversight Group in June 2004 (three months after sanction) show that there were scope items still in flux … "retained buildings and fire marshal requirements?" Ex. SOA-295 at 3.

898. Thus, the Carriers knew that their design was flawed and not up to code. Other scope problems were foreseeable and resulted in additional costs. For instance, SR was to replace the fuel-fired turbines with electric motors, yet the Carriers sanctioned the project even though they still had not decided whether they were "deferring PS 1 electrification or eliminating it entirely." Two months after BP sanctioned the project, in April 30, 2004 A. Bolea, writes an email stating that he does not see a "clear way forward. My intuition is that we will end up deferring PS1 electrification or eliminating it entirely. To be candid it always was marginal for BP and it's not going to take us much to back away from it. I would suggest that you begin thinking about a plan that does not include PS1 electrification." Ex. SOA-26. As State witness F. Adams testified, much of the work that was added after sanction was related to items that should have been included in the original scope. He further states that "with more appropriate project planning and engineering, Alyeska would have recognized prior to sanction that the scope of the project would be much larger than envisioned in the 2004 AFE S020 sanction documents." Ex. SOA-275 at 57. This credible testimony is supported by the evidence and entitled to significant weight.

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[479] Howitt confirmed that many of the subsystems identified in the Bailey Report were contained in the buildings that were projected to be taken out of service. Tr. 6667:3-11(Manifold Building); 6669:11-17 (Relief Bay); 6669:21-6670:6 (Booster Pump Building).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

899. Particularly relevant to the actions of the Carriers is the fact that the fast track schedule prevented the use of lump-sum contracts. Lump-sum contracting strategy was part of the "path in achieving the cost/schedule/operability expectations that lead [sic] to project approval." Ex. SOA-460. At sanction, SNC estimated that 90 percent of the work was "[g]eneral Installation of New Facilities" and 10 percent was "[w]ork for and inside existing facilities." Ex. SOA-458. The general installation work would be awarded as lump sum contracts the work for and inside existing facilities would be awarded as time and materials-fixed fee. [480] *Id.* In late December 2004, the SNC estimating department changed this to 70% of the work was now "work for and inside existing facilities" and 30% was in general installation of new facilities. *Id.* This shifted a considerable amount of work from the "lump sum" package to the "time & materials" package. *Id.* As a result of this change in engineering, the cost estimates upon which the decision to sanction was based was totally changed.[481]

900. The State avers that the failure to achieve lump sum contracting was a clear indication that the basic design assumptions of the project were incorrect. State RB 51. The State is correct. Carriers' witness Emmert conceded in his testimony that the design basis at the time of sanction was so ill-defined that "a prudent contractor would never have accepted a lump-sum contract." Ex. ATC-30 at 75:7-9. However the Carriers did not reevaluate the design nor the cost estimates for the design. This was not the actions of a reasonable utility manager.

901. The Carriers claim that the failure to procure lump sum contracts was not significant and that the change to time and materials contracting was reasonable, because it is an accepted contracting method. Carriers IB 171-73. However, the State is correct that the inability to use lump sum contracts was not the most significant problem; rather it was an indication of a much more fundamental problem – deficiencies both in the design and preliminary engineering. The imprudence and unreasonable management of the Carriers was in not reevaluating their design and cost assumptions once they were aware that the design was so deficient that "a prudent contractor would never have accepted a lump-sum contract." Ex ATC-30 at 75:7-9. Further, it was clear evidence that the original sanction was unreasonable, because the failure to achieve lump sum contracting was a direct result of inadequate preliminary engineering.

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[480] F. Adams testified that "[o]n a cost-plus contract, the contractor cannot reasonably be assigned the role/responsibility of maintaining vigilance against cost increases and schedule slippages. Thus, it is the owner's responsibility to maintain an independent organization capable of monitoring cost and schedules; owner must supervise and control its contractors." Ex. SOA-275 at 146.

[481] Yaege, President of Conoco Alaska, Inc. testified that the contingency was reduced due to the assumption that a significant amount of the work would be performed under lump sum contracts. Tr. 4822:16-24; *see* also Ex SOA-287 at 53.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

902. The Carriers decided that they could automate TAPS, that 77 buildings could go idle or cold,[482] that they could replace gas-and fuel-fired drivers with electrical drivers. They assumed that PS 3, 4 and 9 would have all facilities replaced by engineered truckable modules constructed off-site. Ex. SOA-670 at 3. The modules were to be pre-wired, minimizing "site construction and field connections." Ex. ATC-147 at 267. The modules were expected to be designed for maintenance with panel door access but would not accommodate continuous presence of personnel. *Id.*

903. The SR modules are not self-sufficient since extensive tie-in work is needed to be done in the field.[483] Further, the amount of wiring and cabling was much more than anticipated. Ex. SOA-308 at 2. AFE SO20 Supplement 2 states, "[s]ignificant increases in the quantity of pipe rack and cable tray support structural steel, and electric cables have occurred during the detail design development. These design development issues are not considered to be scope changes, but have significantly contributed to the overall cost increase." Ex. SOA-65 at 12. The Justification and Premises Document for Supplement 4 confirms this. "The project scope was primarily new stand alone Pump Station facilities (Greenfield Facilities) with minor interconnecting work associated with tying into existing retained facilities (Brownfield Facilities)." Ex. SOA-218 at 4. "Regulatory and operational requirements identified during conceptual/preliminary engineering were incorrect, most notable of which were those associated with the Brownfield Facilities and interconnect requirements to the Greenfield Facilities." *Id.*

904. For years they had known that automation projects would require extensive "brownfield" work to implement. The Bailey Report identified the instruments (new or modified) which would be affected by the automation scope of work. They were itemized by specific tag number, by location, and P&ID (process and instrumentation diagram). Ex. SOA-731 at 12-25 (Bailey Report App B). Bailey also had equipment specific guidelines which were adopted during the markup of the P&ID's for automation cases E and F. Ex. SOA-732 at 4. It also identified numerous "subsystems" which would require consideration for automation upgrades (this list is for information taken by data loggers or hand held manual devices carried around the pump stations by Operators). Ex. SOA-739 at 3-7. To unman the stations and monitor non-MLU equipment that was to remain at the pump stations, the data points would need to be integrated into the SR systems. This shows that brownfield work would be required under electrification. However, the Carriers ignored Bailey and this record is devoid of any evidence contradicting the findings in Bailey.

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[482] Ex. SOA-60 at 9, 5; *see* also Ex. SOA-1 at 75.

[483] As discussed in 2007 below, the SR AFE Audit dated January 1, 2007, confirms this. Ex. SOA-308 at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

905. Further, Anadarko is correct that the Carriers were aware that they did not know the full scope of the SR project at the time of sanction. For instance, Hisey testified

> the scope that they knew is basically what is identified in the AFE. There was additional scope that they did not know, and some of that scope that they did not know they knew they did not know. . . . And what you don't know in this case had potential to be potentially large. If the project is economically justified only, which this project was driven by economics, what you should do is you should go figure out what is the cost of what you don't know and what is the benefit, is there additional benefits from that or does it change your benefits. Since it's an economic project, it requires a lot of rigor around the economic evaluation. The fatal flaw in this whole thing was that scoping process and moving forward on a project that there was a lot of unknowns around, and those unknowns stood the potential to drive the entire project economics.

Tr. 3276:22-3277:18.

See also 3278:14-3279:7; 3280:2-14; 3891-92. D. Hisey was a credible witness. At the relevant point in time he was the COO and thus was familiar with the SR project. His testimony therefore, is given significant weight.

906. The Carriers were aware of the importance of completing sufficient engineering prior to execution, especially in light of the fast-track schedule. Just one month after sanction an Exxon analyst discussed the importance of scope management. "Due to the magnitude and tight timeline of the TAPS Pipeline Strategic Reconfiguration Project (including the cost implications of delayed start-up), scope changes should be rigorously managed to avoid scope creep and project delay. Therefore, some restriction on scope changes (i.e. only allowable for safety or environmental issues) could be considered. Ex. SOA-290 at 3-4.

907. Anadarko is correct that the Carriers needed to develop a high level of confidence in the scope as well as determine with certainty the economic benefits of the project and this would have been accomplished if they had proceeded to final engineering. D. Hisey testified as follows,

> [b]ased upon the fact that prudent project management recognizes the need to advance your engineering to far enough along to a state where you have fully developed the scope and fully engineered it to a point of having high confidence in the cost and, similarly, the organization would have to have high confidence in the savings, …It is prudent to develop it to that point. I think of all the problems that we have identified can be characterized as you could have discovered those through engineering and more work.

Tr. 4035:22-4036:16.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

908. However, the Carriers decided on the December 31, 2005 date to complete the project and there was no time to complete final engineering before beginning project construction. Concerning this D. Hisey testified, "But you had to have it done by December '05 to get that advantage" (tax advantage). Tr. 3023:21-22. "That's what set that schedule. That schedule was impossible. And because they had that schedule, they didn't have adequate engineering to get a good cost estimate. And they didn't get a good cost estimate because they didn't have a full scope of work." Tr. 3023 :22-3024:1. D. Hisey's testimony is given significant weight. If final engineering had been completed on the project prior to construction, the true costs and benefits of the project would have been known.

909. Further, if proper protocols had been followed projected benefits would have been thoroughly identified and quantified. As Hisey testified, ". . . [a]s the scope increased and the cost increased along with the scope, these savings were decreasing because the savings were based upon a simplified system. And now there was more equipment left. So it was less simplified, so you have to keep more people around. So you got this working in opposite directions. Costs are going up and savings are going down, which is making the project worse instead of better." Tr. 4038:2-9. The estimate of benefits was flawed, and the projected benefits were not achieved. Based on the flawed schedule the tax benefits were never going to be realized so it was not reasonable to factor the tax savings into the benefits. Buildings that were assumed demolished had to be retained, requiring fire and gas suppression upgrades and preventing the Carriers from avoiding these costs. The estimate of reductions in major maintenance were unreasonable (a base-year estimate that was "factored" for future increases assuming as high as 50 percent increase every year for several years). Additionally, the projected O&M savings were the result of automation and not the result of replacing the legacy equipment with electrical equipment.

910. Anadarko argues that if final engineering had been done correctly the project would most likely have been determined uneconomic, and a prudent manager would never have constructed the project. This decision is not going to speculate as to the possible outcome of acting prudently. Conversely this decision does reach the conclusion that the actions undertaken by the Carriers were not those of a reasonable utility manager. Further, the expenses in this case are costs which a reasonable utility management would not have sanctioned in good faith, under the same circumstances and at the relevant point in time.

911. The State correctly points out that the level of project definition is inversely proportional to the amount of contingency funding required. Ex. SOA-275 at 8. The Carriers sanctioned electrification before sufficient engineering and project definition were completed due to the fast track schedule. The State is correct that a prudent pipeline manager would ensure an enhanced contingency funding under these circumstances. State RB 30. However, the Carriers did the opposite. Prior to sanction they had been warned that the contingency funding was low. Exxon's documents show that they had

20140227-3052 FERC PDF (Unofficial) 02/27/2014

concluded the contingency was low relative to the current level of project definition. Ex. SOA-258 at 3. In response to Larkspurs noting deficiencies in the project's engineering, the Project Controls Manager (Ahrens) requested additional contingency. Ex. SOA-255. However, instead of increasing the contingency, the Carriers reduced it. "The contingency in the cost estimate was less than 7%, which is a much smaller amount than what should have been included at that level of engineering. Only part of the contingency was approved." Ex. SOA-66. About a quarter of the contingency requested was not approved. Ex. SOA-254 at 6. Accordingly, it is concluded this action was not the action of a reasonable utility manager.

912. Ex. SOA-11 at 17 shows the affiliate relationships between the Carriers' and their ultimate owners or affiliated producers. As a result of SR, the affiliate producers booked additional reserves which resulted in a DD&A improvement of about $0.20/bbl for the Alaska BU. This also extended the life of the pipeline to 2050. If the project was cancelled the additional reserves would be at risk. The booking of more reserves supports Anadarko's arguments of inappropriate affiliate considerations. As Staff avers, the Carriers failed to meet their burden that they were prudent in light of the evidence in this case in addition to the fact that they inappropriately considered affiliated producer interests in reaching the decision to both sanction and continue with the project, with no current ratepayer benefit.

913. The State is correct that the Carriers reliance on the conclusions in the "checklist" IPA report, while ignoring the contrary reports and critiques of Larkspur and Alyeska engineers and operators, provides inadequate support for the sanction of SR at a state of engineering development far below industry standards. Additionally, third party reviewers, as the State points outs, were not tasked with and did not have the time, budget, or capabilities to undertake an in-depth review of the reasonableness of the engineering scope. Nevertheless, despite the mentioned constraints, the third party reviewers gave significant warnings about the SR project but the Carrier ignored these warnings.

914. As the State points out, the Carriers cannot excuse their actions by blaming the SR PMT, Alyeska and the contractors.[484] The SR PMT, was created by the Carriers and was

[484] Carriers IB 7 (labor and material shortages led to delays and escalating costs; greater amount of work needed to be done in a 'brownfield' environment, the lead contractor failed to deliver the leadership personnel and engineering staffing it had promised). *See also* Carriers IB 180 ("setbacks caused by labor problems resulting from the 2004 oil sands boom, the unexpected surge in North Slope project work in 2006, and the unexpected retirement of the highly regarded project manager slated by EPCM contractor to run the project"). The State is correct that these were not the primary drivers for the project's excessive expenditures. Further, the State is correct that these problems are all related to the management and execution of the SR project. State RB 133.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

staffed primarily with Carriers' secondees. The PMT reviewed the bids and recommended hiring SNC. Ex. ATC-25 at 5:4-6:2.

915. Further, the JPO and the Office of the Attorney General did not validate the SR project as a prudent business decision. Ex. SOA-544 at 5:18-6:19; 11:7-16. As the evidence in this case shows this is not what they do and not within their expertise. The JPO in particular raised questions about the project. Exs. ATC-233 and ATC-198.

916. The Carriers did not take reasonable steps to inform themselves nor did they give reasoned consideration to the information they had. Accordingly, their actions are not the actions a reasonable utility manager would have made in good faith, under the same circumstances, and at the relevant point in time. The Carriers misrepresent the facts in their briefs and in support of their actions. For instance, in response to Anadarko's arguments, the Carriers argue that electrification was a viable alternative. They contend that as "Alyeska recognized in 1999, "operation of the electric drive should be simpler, more reliable, and require fewer people to operate and maintain." Citing Ex. ATC-105 at 17. Carriers RB 17. The Carriers misstate the facts.

917. What Alyeska recognized in 1999 was that the "base case" using the AVON drivers should be improved. Ex. ATC-105 at 17. The study also recommended a strategy to migrate to nearly "unmanned" operation. "A simplified analysis indicates that the pumping oil function can be supported, especially with automated controls, by two operators on duty, four people total on site." *Id.* In terms of electrification the study concluded, "[c]onsidering CO2, installing a new large turbine at PS 9 or electric drives at PS 7 and/or PS 9 may be viable options" with caveats. *Id.* The caveats for the electric drive: higher technical risk since it is a significant change in equipment and adds dependence on the power utility and thus this is tied to fuel prices. If fuel prices remain low this is not an attractive option. *Id.* Then it points out the advantage which "should be simpler, more reliable, and require fewer people to operate and maintain." The large turbine GE LM 2500 would be a low risk change because the equipment is proven and reliable. It provides a marginally positive economic benefit. Heat recovery equipment could be included with this installation to provide station heat and improve economic benefit. *Id.* It is almost as if the Carriers are not reading their own documents or trying to rewrite history. Additionally, it bears repeating this study only focused on electrifying PS 7 and 9.

918. In the BP electrification sanction memorandum BP admitted that "one of the enablers of pump station manpower reductions is the new oil spill plan," and "]t]he resulting automation provides an opportunity for a step-change reduction of 285 full-time positions," concluding that "[n]ew automation will enable elimination of field-based pipeline operating personnel, reduce support costs and deliver a $44 million ($17m BP net) per annum cost reduction by 2008 from current levels." Ex. ATC-261. *See also* Ex. SOA-552 at 47.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

919. Sanders testified that the project suffered from not being adequately engineered at the time of sanction. "That is what I have testified to. The owners have said that, AFE audits have said that. That's the core of what's wrong here. When this project was sanctioned, it was not mature engineering that took it to that level. And we can talk about bits and pieces of this, but that is the main core fatal flaw. You hadn't done adequate engineering at the time. You did not meet the processes provided for by the owners to get the project sanctioned." Tr. 1053:12-1054:15. As stated before, Sanders' testimony is given significant weight.

7. What happened in 2005

920. In January 28, 2005, M. Tudor (Exxon) writes a letter to the other owners, D. Hisey and J. Barrett, expressing his concerns about the execution of the SR project (AFEs S020, S023, S024, S025, S026, S028 and S031). Ex. SOA-343. His main concern is that the project has seen $100M or 44% cost growth from Gate 2 ($234M total estimate, with no contingency). He states that the economics of the project, from a return perspective, have continued to decline as costs have risen. Additionally, according to Tudor, the project continues to have cost and schedule challenges, in particular issues resulting from the unanticipated motor vibration problems. He concludes by saying among others that "we would like to understand what options exist to limit Project expenditures to < $300M while not compromising the integrity of the Project." *Id.*

Stream of emails February 2-7, 2005

921. An email from C. Hatley dated February 4, 2005, discusses cost overruns for the project. Ex. SOA-339 at 3. On February 7, 2005, another email from C. Hatley states that the PMT is looking into schedule impacts due to potential delivery problems with the motors "as the vendor continues to work to solve vibration problems." *Id.* at 2. In a response dated February 7, 2005, T. Gaul talks about the motor problems. He states that it "sounds like another example where a small step-out in technology turned out to be much more difficult than planned. In hindsight, we probably should have further increased contingency to account for new technology – I didn't realize at the time that this step-out was significant. Plus, we were already recommending a much larger contingency than the operator and the project economics were not all that robust. The list of contributors to the cost increase (materials, regulatory, scope creep, errors and omissions in the estimate) strikes me as "the usual suspects"…" *Id.* at 1.

922. C. Hatley responds that "unfortunately the technology step-out was never brought to our attention." Other projects have installed larger motors, and used variable frequency drives. "The step-out is the large motor with a wide frequency band. Also, it turns out that there is more brownfield work involved than we originally understood." *Id.* Based on a ruling from the Fire Marshall several buildings will need to be kept in service and work done to maintain them. Additionally, in supposed clear areas, there "turns out to be numerous lines, cables, etc. buried that must be contended with." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

SR Updates – February 18, 2005

923. A BP document dated February 18, 2005, gives significant insight into the status of the project at this time. Further, it is also deemed admissions against interest and further shows lessons learned. Note that this document was not considered in the determination of prudence at sanction. The document starts by stating that the pipeline SR program is "nearly 50% complete" and defines pipeline SR as comprised of four projects, "Electrification, Lifecycle Upgrades, Pump Station 5, and Ramp-down stations. Electrification and Lifecycle are described as comprising "90% of SR costs." Ex. SOA-166. The document states that "there has been significant loss of value to "Electrification", the current view of money forward economics is NPV $101m, IRR 26%, and full cycle NPV $77m, IRR 19%."

924. The document points out that SR "will have cost overruns and require supplemental FMs in April." *Id.* "Cost estimates for worst case scenarios may breech important authority levels. Current estimates for Electrification range from $93m (+15%) to $100m (+23%), with better clarity by April after construction contracts for 2005 installation work are finalized." *Id.* It contends that savings are delayed by one quarter, since the start-up of two electrified stations will now be achieved in 2005. *Id.*

925. The cost increases (20% or $5m) are attributed to commodity prices (steel, wire). "The remainder ($21m) stems from insufficient detailed engineering (Front End Loading) at sanction, and to the choice of a program management contractor without Alaskan experience. Clearly, the cost range was not adequately characterized or the assurance process missed this. However, other urgent drivers around saving were avoided major maintenance, tax bonus opportunity and the need to replace aging equipment drove us forward with less detailed engineering than would normally be prudent." *Id.* The key learning was that a contractor with more Alaskan experience could have anticipated these cost uncertainties for increases related to regulatory environment/fire code requirements ($6.9m), hazop and operability, and installation contracts in "Brown-Field" conditions." *Id.*

926. The document lists several mitigation options that were put in place. The project team was strengthened with Owner secondees, a technical oversight group was formed, staff within Alyeska was reassigned and the VMT SR project was slowed down. "Other more dramatic options entailing stopping the project are considered, but are very onerous from financial, legal and reputational aspects. However, should the issue around motor vibration remain unresolved by April, a program time-out would likely be called where we will re-examine the competence and accountability of entire project management team, and contractors." *Id.*

Email from J. Barrett February 21, 2005

927. At this point in time they do not have a good cost estimate or schedule. In an email J. Barrett wrote that an outside resource was assigned to help SNC finalize the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

project schedule and a new schedule was delivered. Ex. SOA-494. He also states that the PT has been struggling with SNC's poor performance in project management and controls. *Id.* SNC is still not able to give us adequate data on costs. *Id.*

February 22-24, 2005

928. Al Bolea questions the testing done to determine the long-term reliability of the electric motors. "The SR team will determine what additional testing will be required to verify the long-term reliability of the electric motors. Ex. SOA-216 at 12.

February 2005 Change in Contracting Strategy

929. Around this time frame the contracting strategy had to be changed from lump sum to "time and material" contracts. An SR Installation Contract Strategy White Paper dated February 2005 states that "from the beginning of the project, it has been the intent of the Project Team to award as much of the new module installation work as lump sum and minimize the time & material work to inside existing facilities." Ex. SOA-458. The White Paper has the following information:

- The original plan was to bid Package A – General Installation of New Facilities - as lump sum, Packages B & C – Work for and inside existing facilities - as Time & Materials/Fixed Fee. Package B & C are primarily electrical and instrumentation related. The budgets and forecasts from Preliminary Engineering were originally allocated to those packages long before assembly of the packages. Throughout 2004, the numbers in SNC's cost reports continued to show that 90+% of the work was in Package A and 10-% of the work was in Packages B & C.
- . . .
- In late December 2004 the SNC Estimating department . . . to update the budget/forecast numbers from preliminary engineering which resulted in a large swing in dollars between the respective packages. The packages now sit with approximately 70% of the work in packages B & C, and approximately 30% in package A. . . SNC didn't highlight this significant development, APSC discovered it in reviewing the SNC January cost reports on February 9th, 2005. The effect shifts a considerable amount of work from the "lump sum" package to the "time & materials" package.
- … schedule effort undertaken because of the motor vibration issue now indicates that module delivery dates and the revised NTP dates (because of late engineering packages) have caused a shorter construction season in 2005. All field work will now be undertaken concurrently. .. Winter comes to all stations by October 1st and winter productivity factors can be 50-100% worse than summer.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

- An additional element in the contracting equation is the number of drawings in the construction packages for each pump station. The IFR drawings for PS-4 were just issued in the past week. Package A (new installation has 769 drawings, package B has over 1,200 drawings, and package C has over 300 drawings. This totals over 2,100 drawings for PS-4 excluding the Turbine/Generator enclosure erection and installation …

Id. at 1-2.

930. The recommendation was a contracting strategy based on time and materials with a fixed fee, and a target price around that fixed fee. *Id.* at 3. The late arrival of engineering packages and the compressed timeframe for contracting and construction were the reasons for a change in the contracting strategy. *Id.*

931. Dr. Makholm, in his written testimony defines lump sum contracts as a contract for specified services for a fixed price. Ex. SOA-525 at 33:10-11. Such contracts transfer the risks of overruns to the contractor. *Id.* at 33:13.

932. The Owners were pressuring for lump sum contracts as the best assurance on costs. Ex. SOA-203. By February 25, 2005, they are concerned about uncertainty with the project, specifically, the costs and the transitioning from SNC to Alyeska of the project control functions. *Id.* 1- 2. The SR team is to focus on completing PS 1, 3, 4, 5 and 9. *Id.* at 1.

Email February 28, 2005

933. In late February construction contractors had not been selected. This is ten months from the scheduled completion. Ex. SOA 459. There is an email from I. Levitt that states that in order "to be mobilized with staff, craft, equipment and bulk materials by June 1, we need to select construction contractors NOW!" "We do not have time to bid and evaluate contracts with multiple contractors at multiple sites." *Id.* at 2.

March 2005

Email March 4, 2005

934. An email dated March 4, 2005, from S. Johnson states that A. Bolea (President BP Pipelines (Alaska), Inc., M. Rocereta, TAPS Performance Management consider the project to be a "Train Wreck." "They want us to identify weaknesses in BP (owner) and Alyeska (TAPS Service Company) that led to this current condition and how to mitigate going forward . . . including taking a "pause" to get things back on track." Ex. AT-252.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Project Assessment

935. In March 2005, there was a project assessment. A BP document which appears to be slides from a presentation was admitted into evidence. The drafters included a representative from Ventana Systems, Inc.. The general characterization of the project was that it was an underperforming project suffering from the interaction of a number of items. Such as, late definition, scope creep, design changes leading to delays and inefficiencies; change knock-on effects; technology surprises; buildup of schedule pressure associated with approaching summer construction season; "inadequate resources (time, tools, etc.) to effectively and efficiently evaluate tradeoff options." Ex. SOA-341 at 4. The assessment continues with a statement that a lack of integrated program schedule undermines the accuracy of comprehensive program cost estimates. *Id.* at 5.

936. The document states that the project is in need of a recovery plan. *Id.* at 7. Concerning the schedule and cost model a number of possible next steps are listed including: "more realistic cost projections," "[h]igher accuracy measurement and forecast of project," "[i]ncrease accuracy of evaluation" and "[e]xamine a wider range of interventions including phasing." *Id.* at 8.

937. Potential PMT Interventions are listed as: "[r]evised phasing (sequential vs. parallel construction); [s]chedule extension without revised phasing; [a]dded resources – [p]rogram and [p]roject; [f]urther de-scoping; [d]elay construction to allow debugging of engineering" and peer reviews. *Id.* at 9.

Project Execution and Implementation Planning Review March 5, 2005

938. This document states that scope is still not frozen. Ex. SOA-247 at 11. Another problem listed (which had been identified prior to sanction and still persisted) is that it "assumes near flawless execution." Additionally, the review states that "accuracy of task durations, task relationships, milestone dates and overall schedule are indeterminate." *Id.* at 11-12. To wit, the schedule appears to be developed from top down, approximately "1/3 of the activities have less than 10 days float and many activities show negative float in the forecast." *Id.* at 12.

Email March 11, 2005

939. Notwithstanding the fact that the project had significant cost overruns and delays, the Exxon tax department recommended that the project be accelerated to meet the "January 1, 2006 placed-in-service requirement to achieve the NPV bonus savings" ($80 million of incurred capital costs through December 1, 2004, are eligible for 50% bonus depreciation). Ex. SOA-240 at 2. At page 1 of this document, in an email dated March 14, 2005, C. Hatley notes that the "PV will be substantially reduced if any or all of the stations are delayed into '06." Ex. SOA-240.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Project Assessment Team- Findings/Recommendations- Report to the Owners - March 16, 2005

940. A March 16, 2005, report to the Owners by the Project Assessment team states that the original schedule is in jeopardy and has a less than P50 chance of succeeding. Ex. SOA-304. This is the result of a number of things: scope additions (power generation), Fire Marshall requirements and engineering changes since the start of the project. These have resulted in late delivery of engineering which impacted material delivery, permitting, contracting and fabrication. Vendor pump motor problems also caused delays. The report also points out that the project execution plan, project cost and schedule do not reflect the current status of the project. *Id.* Lump sum contracting could have been used but the current schedule makes this approach difficult. *Id.* Moreover, the AT[485] stated that at "this time a start up date cannot be defined with high confidence." *Id.* at 7. At this point in time they are still trying to get a handle on project costs. *Id.*

Special Review by Internal Audit March 16, 2005

941. An Internal Audit concluded SNC's Project Control personnel are not effectively controlling the project. (March 16, 2005, letter). This was for AFE S026 (Pump station 5 upgrade project). The estimate had increased from $11.8M to $19.4M. The letter states that the concerns identified with AFE S026 may be indicative of similar issues pertaining to the entire Strategic Reconfiguration Project managed by SNC. Ex. SOA-476 at 2. A number of root causes are listed one of which is "project "red flags" were not acted upon and elevated/disclosed with a high sense of urgency when they first arose." *Id.* at 3. The reviewers listed as a root cause the fact that the SR Team originally assumed that SNC's cost control process was adequate and would not require significant monitoring by the SR Team. *Id.*

Email April 9, 2005

942. J. Barrett by email writes that "we have a bit of a crisis on our hands with SNC. Ex. SOA-359. He points out they are not making their deliverables and recent delays in engineering and material delivery has affected the module fabrication schedule. The scheduled installation of "freeze-back" piles is in danger due to late submittals and changes to pile design. Ex. SOA-359. He asserts SNC has to be put on notice that this is not acceptable and notes that work has already been taken away from SNC. *Id.* Further he states that this will be reported to the Owners.

Letter to SNC- April 13, 2005

943. A letter is sent to SNC indicating its poor performance. Ex. SOA-216 at 40. "The primary disappointment is that SNC has failed to meet critical engineering and

[485] The Assessment Team. *Id.* at 5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

procurement milestones, including the recovery plan that SNC submitted last August. These deficiencies have caused major delays and economic loss, and have eroded Alyeska's and the TAPS Owner's confidence in SNC's ability to accurately predict cost, schedule, and quality of work." *Id.*

May 2005

944. A May 2, 2005, memo states that SNC has done a poor job in cost control. Ex. SOA-216 at 33. "Veco and PPC will receive the IFR packages and prepare estimates and work plans for field work as part of the recently approved contracting strategy. . . Estimates that come from PPC and Veco will be reconciled with the SNC Lavalin/Larkspur estimates and will be the primary input for the supplemental AFE requests for S020 and S026." *Id.* "An outside resource was assigned to help SNC Lavalin finalize the project schedule." SNC's "scope has been reduced to engineering, procurement, and engineering support during construction. SNC will not perform construction management as originally planned. Alyeska is in the process of taking over construction management." *Id.* at 34. Upon requesting additional help for cost controls from the Owners (no resources were found), the PMT assumed control of these estimates. *Id.* at 34. Looking to hire "cost engineers." *Id.* The SR PL project manager is developing a plan to place a full-time manager in Edmonton for the next two to three months to ensure finalization of work packages according to project priorities. *Id.* at 35.

945. A "Keep You Posted" memo dated May 3, 2005, from John Barrett announces the reorganization of the SR Team. Now Alyeska personnel will be in key positions. Alyeska will also be managing construction. Ex. SOA-216 at 20. SNC has been replaced and will do engineering support.

946. The new SCADA System designed by Control Systems International, was conditionally accepted by Alyeska on March 1, 2005. (AFE 370). Ex. SOA-216 at 43. Site testing is scheduled to conclude by June 1, 2005. *Id.* Testing delays were the direct result of "approximately 950 identified system deficiencies requiring vendor rework." *Id.* As of May 2005, there are still over 100 open issues. *Id.* The new UCOS system has been installed so it can operate in parallel with the SCADA. *Id.* The final cost is within 10% of the upper limit of the forecast or $8.6 million. *Id.* at 44. A "level III work breakdown structure that integrates all activities, including final design, the appropriate operational, regulatory, and Owner reviews, the field construction execution plan, preparation of O&M procedures, training, functional check-out, commissioning and start up" needs to be prepared. *Id.* at 55.

947. The document also recommends that an Alyeska "supervisor with sufficient signature authority to disposition Design Change Notices (DCN's) should be assigned and working in the SNC offices until mid May or early June." *Id.* at 61. It points out that "regional and cultural differences between SNC's typical engineering product and detail and Alyeska and Alaska industry product and detail represents an understated area of conflict concerning review and approval of issued packages." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

948. A May 4, 2005, letter from SNC notes that there are many factors which impacted the status of the project. "Most significant among these is the very significant number of Design Change Notices (approximately 130) that have been generated by our personnel and approved by Alyeska. Many published studies, and our own prior project experience, have demonstrated that scope change of this significance will have a serious impact on both the cost and schedule of any project and particularly on a "fast track" project such as this one." Ex. SOA-456.

949. A preliminary analysis of the project was done by BP in May 17, 2005. Although the document admitted into evidence bears a BP heading the drafters listed include one person from Exxon, one from Business Dynamics and one from Ventana Systems, Inc.. Ex. SOA-325. The bottom line of this document is that there is evidence "that engineering scope has grown ~ 50% as measured by engineering hours." At this point in time, the engineering delay "**only** ~ 5 mon longer from original estimate" and "engineering error rate not yet decoded." *Id.* at 2 (emphasis in original). The "impact on construction awaiting promised estimates from construction team, not yet delivered." As a result, the "NPV impacts not yet quantified." *Id.*

950. Significant, slightly over one year into construction is the following, the analysis is preliminary for the following reasons:

- One critical measurement is said not to exist
  - SNC measures neither discovery of engineering errors nor design rework man-hours nor drawing revisions to correct errors; indirect measurement is possible , but will require alternative data from SNC
- Still missing critical promised estimates
  - Estimates of impacts of potential engineering errors on construction schedule and cost not yet received

Id. at 3.

951. As "[u]nderstanding the existing DCNs"[486] the following are listed: essential components of scope were previously overlooked, part of the existing design is recognized as unworkable, and had to be redesigned, some expansion or redefinition of scope (example PS-1 self power vs. purchase power may add scope and/or render obsolete some of the existing design), "customer overrides" "APSC fault of technically adequate design components (likely to be differences of opinion on degree to which a given DCN is in category 3 or 4)." *Id.* at 8.

[486] DCN means design change notice(s).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Owners Meeting May 18, 2005

952. In an Owners meeting in May 18, 2005 a number of items were discussed concerning SR. An audit subcommittee report was discussed regarding the "overall control environment and concerns relating to cost estimation and cost control." Ex. SOA-366 at 2. A. Bolea questioned whether the SR Team has the right resources to maintain cost control. *Id.* One participant acknowledge that the SR Team waited too long in trying to get SNC to address the problems with the project and the SR Team should had gotten directly involved earlier. *Id.* at 3. Two reasons for the scope changes were identified. To wit, first, "SNC was not performing in the areas of planning, scheduling and project controls. Second, the SR Team struggled internally to improve its coordination with Alyeska operational personnel." *Id.* Of note is the fact that they are rewriting the construction execution plan to facilitate implementation and coordination with Alyeska's processes. *Id.* "[G]reat strides had been made in the past two-to-three months in coordinating the activities of the SR Team and Alyeska's operations and maintenance personnel." *Id.*

953. M. Tudor stated "that it is difficult at this time for the Owners to know whether the project is under proper control." He "noted the prior audit finding had stated that the estimates and actual costs were off, but that there never has been an explanation of why. He expressed concern that proper controls be in place for the construction phase of the project, and expressed a preference for competitive, lump-sum bidding." *Id.* The SR engineering design status was reviewed and it is "one-to-two months behind schedule." *Id.* at 4.

June 13, 2005 Discussion with D. Peattie

954. In this document one of the lessons learned is the choice of SNC-Lavalin (Edmonton) as the primary engineering contractor, procurement contractor and construction manager. According to the document, SNC has been a major liability to the project. Ex. SOA 277. "Poor cost estimation, weak Alaskan engineering and poor project management controls has contributed significantly to the unexpected costs experienced to date. Future major projects should limit their engineering contractors to companies with a breadth of Alaskan regulatory and Alaskan design criteria experience." *Id.* Another major driver of increased costs were design change notices as a result of operability and HAZOP reviews. The recommendation is that future major projects should include a single senior Alyeska management champion "accountable to the CEO, responsible for the timely scheduling and execution of the joint operability reviews, moderating the outcome and managing the commissioning transition to operations." *Id.*

Email June 27, 2005

955. "The "going is rough" with the Electrification reconfiguration project FM." Ex. SOA-383. This is the start of an email from M. Rocereta. He gives the latest monetary estimate for SR and the lifecycle upgrade projects at PS 5 and ramp down stations which

20140227-3052 FERC PDF (Unofficial) 02/27/2014

are being done under separate FMs stating that the costs of all are increasing. *Id.* Concerning SNC, the email states that it has turned out to be largely incompetent at designing, managing the fabrication and forecasting engineering, fabrication/construction costs. *Id.* "Their unfamiliarity with Alaska codes and regulations has been a liability from the beginning." *Id.* The email also states that "Alyeska's lack of design team and project team integration has led to numerous design changes (increased scope) that have also significantly driven the costs higher." "The scope management was largely ineffective because the missed scope mainly included things that were needed for the pump stations to function. The undiscovered scope was missed in preliminary engineering but discovered in HAZOP or Operability reviews." *Id.*

956. He also states that Alyeska has taken over project controls from SNC. Alyeska hired Larkspur to develop "parallel estimates on the remaining portion of the project. The email claims the Owners took mitigation steps, i.e., "greatly reduced the scope of the work originally intended for the team (removed all the Valdez terminal work), changed the project strategy from schedule driven to cost driven (delayed the project by six months), encouraged them to get expert outside support (new construction manager, new FCO/Commissioning manager, Controls specialists), and have enrolled EPTG Project Excellence team to help us understand more fully what is causing the overruns and recommend interventions." *Id.*

July 19, 2005 document "Draft 7"

957. This document's background explains how conceptual engineering was completed at the end of 2002. Preliminary engineering finished at the end of 2003. AFE SO20 was approved in March 2004, and major equipment was ordered immediately. Ex. SOA-237. "The original deadline for project completion meant that the project would be approved before Detailed Engineering could be completed. "The 2005 deadline was driven by regulatory commitments, including Fire and Gas system upgrades, and other economic considerations approaching $100M for a one-year delay. The deadline for Fire and Gas Systems upgrades was later relaxed by the regulators until the end of 2006, but only after the AFE was approved and regulators were convinced that Alyeska intended to replace a significant portion of the existing facilities." *Id.*

958. It continues describing how "some of the assumptions that would have worked in other places were not feasible in Alaska and the design had to be modified after the AFE was approved." *Id.* at 2. Additional work and delay was the result of several uncertainties which developed during Detailed Engineering. For instance, negotiations for commercial power at PS 1 and 9 were unresolved for several months. "The final resolution eventually changed the original design and required a supplemental AFE." *Id.*

> Assumptions for building modification did not meet regulatory approval and ultimately had to be revised. The "Retained Buildings" study took months to complete and resulted in several changes to existing facilities. Air emission limitations caused changes to the back-up generator design

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> and station power requirements were not identified during Conceptual and Preliminary Engineering. Once the final equipment selections were complete, it was determined that the modules were not sized large enough. The increased size changed foundations, fabrication costs, material quantities, labor and transportation requirements. The seismic design did not fully limit stresses which affected pile spacing and size. And last, the telecommunications provider was changed late during the project, and that caused changes to the design. The changes added significant work and cost to the estimates."

Id.

The project management and project control performance of SNC were inadequate. The PMT took over construction management and project controls. *Id.* at 2-3.

959. Additionally, the document states that it "became evident that the original schedule and cost estimate were not achievable." *Id.* at 3. "The new project plan, schedule, and cost estimate were completed at the end of June 2005 with start-up predicted at the end of September 2006. That is a six month delay from the first supplemental AFE, and a nine month delay from the original plan. The cost estimates show an increase of 65%." *Id.*

960. The document also points out that the "level of definition at the end of Preliminary Engineering was not adequate to accurately predict costs and schedule, and the project was funded without enough contingency. The contingency requested in the AFE was approximately 7%, and only part of that contingency was approved. Based on the level of definition and engineering completed at the time of original AFE approval, the contingency should have been at least 50%." *Id.* It continues by stating that the original cost estimates created during Conceptual Engineering and Preliminary Engineering were low. These low cost estimates were not evident until construction bids began to arrive in May 2005. *Id.* "The savings that will be realized from this project have been re-evaluated and are predicted to be higher those described in the original AFE." *Id.*

961. The "summary portion states:

> In summary, the original schedule was aggressive because of the desire to acquire savings and benefits as soon as possible. The project was approved at an early stage of engineering to allow long-lead materials to be ordered. At that time, the cost and schedule estimates for the remainder of the project did not accurately reflect the numerous challenges this project would face in design, regulatory, and commercial arenas. Low estimates, combined with a small contingency, set unreal expectations for the project cost and schedule. This became apparent over a long period of time, evolving as Detailed Engineering was completed. The current estimates, which are summarized in this request, reflect the true cost and schedule for

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> the project. The project will take longer and cost more than originally anticipated, but it remains the best alternative for long-term operations of TAPS.

Id. at 4.

Monthly Drawings Created by SNC/Hinz July 2005

962. An undated document[487] points out that the scope of the project has nearly doubled, and the budget has grown to match at least part of the scope change. Ex. SOA-330 at 5. The project was "transformed into a crash program with an unrealistic schedule and turbulence." *Id.* Thus, it goes on to state, "balance the project by stretching the construction schedule." *Id.* "A Dilemma" is presented "[c]onstruction has now begun without engineering completion. Both fabrication and field construction are well underway, but the flow of drawing issues has barely slowed, and the flow of revisions is strong." *Id.* at 6. The next page has a number of questions including: "[h]ow many drawings and documents will there be when engineering is complete? (Need breakdown of green vs. brown for both drawings & documents)." *Id.* at 7.

July 21, 2005 Exxon Electrification Project Supplement Review

963. Slides from Exxon's project review dated July 21, 2005, state that the objective of the project was to capture O&M savings and benefits of accelerated depreciation opportunity which influenced the timing of project appropriation. Ex. SOA-200 at 2. According to this document, engineering and procurement are 78% complete. The current schedule start-up is the "4Q06." *Id.* at 3. Field construction began in mid-July. *Id.* Exxon admits that the project appropriation was early at (Gate 3). *Id.* at 4.[488] According to Exxon, the inaccurate estimates were the result of underestimating portions of the project scope, substantial underestimate of overall construction man-hours required, did not include appropriate project share of pipeline shutdown costs in tie-in estimates, did not anticipate the extent of effort required for check-out, commissioning and start-up. *Id.* at. 7. Concerning the incomplete scope (described as the result of underestimating the required project scope) the following are listed: the original project

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[487] EX. J-2 dates this document as of July 2005.

[488] Although the document states Gate 3, based on the limited project definition and cost estimates being in the range of 30% sanction really occurred at Gate 2. Ex. ATC-808 at 4 (Planning and Development Phase: approve work order/AFE, class III schedule/Class II estimate (+/- 15%). Ex. ATC-808 at 13. A performance measure in the 2006 Operating and LRP Assumptions states "FEL Index at Gate 3 authorization." Ex. SOA-216 at 183. Thus, by the Carriers metrics sanction should occur at Gate 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

only envisioned 1/3 of the actual electrical work that was necessary; the amount of foundation piling was underestimated and thicker pipe rack steel was necessary to handle seismic/pipe stress conditions. *Id.* at 8. Exxon lists scope changes resulting from HAZOPs, field operations reviews, regulatory requirements, constructability reviews: OSCP required, heating for additional buildings and change in motor design. *Id.* Material cost increases are listed and schedule delays/performance/rework/regulatory oversight resulted in the project delayed at least nine months. Included in this category are lower than expected engineering contractor productivity, "additional JPO oversight costs/response," motor vibration issue.

964. Exxon lists as an outstanding issue the re-evaluation of project savings and benefits in an attempt to recapture economics lost with project overrun. *Id.* at 10. Options listed were to shutdown the project (only some of the $44 million incurred costs may be salvageable), a temporary shutdown (reassessment) and adjusting the project scope (review scope and expected benefits to identify alternatives to mitigate the extent of cost overrun and improve project return). *Id.* Exxon endorsed the next steps regarding project supplemental funding. *Id.* at 11.

July 25, 2005 - Retained Buildings Fire & Gas Upgrades

965. The Retained Buildings Fire & Gas Upgrades document dated July 21, 2005, states that during "detailed engineering it was observed by the design engineering firm that the controls for some process equipment were located in buildings slated to be taken out of service. . . The Fire Marshal indicated that the fire systems would be required unless the building was truly being removed from operation and therefore not being provided with power. This is in part due to the foam insulated metal clad panel issue described above. This resulted in retention of several buildings slated to be taken out of service, and retention of their fire systems as well." Ex. SOA-104 at 2.

Letter to ExxonMobil Refining July 29, 2005

966. In a letter to ExxonMobil Refining & Supply Company, Mike Tudor President of Exxon details the costs overrun. M. Tudor states that after recommendations from and independent project review "we expect ExxonMobil Production Company (EMPC) to progress a request for supplemental funding to Dallas. It is concluded this is evidence of the affiliate relationships on TAPS. Ex. SOA-334. He further states that the broad causes of the overrun are "inaccurate appropriation estimates (34%), incomplete appropriation scope (18%), scope/design changes (18%), higher materials costs (12%), re-work and delay (18%)." Further, "the challenging regulatory environment and requirements for an extremely high degree of reliability were also not fully appreciated at appropriation. In addition, Alyeska relied heavily on the prime engineering contractor, SNC Lavalin, whose performance to date has been disappointing." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Owner Review August 1-5, 2005

967. An Owner Review document dated August 1-5, 2005, is part of the record in this proceeding. Ex. ATC-318. The document appears to be a power point presentation. It states that the execution plan, the project management system and work processes need improvement. It also states that the sanction amount for the project should be larger as well as the contingency. Further, it points out that the risks to deliverability are greater than characterized and the risk management approach needs improvement. The root causes of the issues with SR are: "sub optimal organization (structure, skill sets); significant changes to project plan (scope)" and "original assumptions turned out to be inaccurate." *Id.* at 4. It notes that the organization needs improvement to be able to deliver the project. The document recommends integrating the project into Alyeska, strengthening project controls, placing management teams in both SNC and Hinz, improving accountability for cost, scope, schedule and related work, having a licensed engineer available locally on the pipeline for prompt approval of field engineering changes and drawings. *Id.* at 6-8. Additionally, the document notes that the creation of new small AFE's has led to fragmentation of the program and recommends that no new AFE's be created and that consolidating those that exist should be considered to clarify program boundary. *Id.* at 9. The document states that there is a question over the level of definition that existed in the project at sanction, the scope in the original AFE changed (power supply, retained buildings, etc.), the man hours, rates and amounts in the estimate and AFE were too low. *Id.* at 10.

SR Project Assessment by P. Flones - August 11, 2005

968. P. Flones, a consultant,[489] carried out an assessment of the project. Ex. SOA-219. In the summary, it is concluded that the completion schedule is achievable and the cost are achievable also, but within 20 to 50 million dollars of the current funding request. Ex. SOA-219. The achievability is contingent on resolution of the control system design and material delivery issues. One of the findings is that the "historical program/organizational structure was not supported by the skill sets of the individuals assigned to the program. Even if the skill sets were present, the organizational structure would have created confusion and less than optimal delivery efficiency. *Id.* Another finding states that the "conceptual SR program estimate set a benchmark that negatively influenced future project decision making and execution approach. *Id.*

969. Concerning preliminary engineering this document finds that the "preliminary design phase of the projects was completed improperly. The time frame was too short and the sequence of work was not correct. *Id.* The document describes the proper methodology that should have been undertaken and states that considering the complexity

[489] A retired BP executive who had done some of the biggest projects that BP had done in Alaska. Highly regarded and respected, according to the testimony of D. Hisey. Tr. 3550:1-6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of the program, the time frame for this effort should have been a minimum of 12 months. The proper methodology would have been:

> first to perform 4 to 5 months of detailed studies involving knowledgeable Alyeska personnel to optimize the new design, identify all interfaces with existing facilities, optimize these interfaces, set design criteria, etc; second to complete design control documents (i.e. P&ID's, electrical single lines, etc.) to allow initiation of the first level of design freeze; third to develop design sketches that depict the scope of facilities in sufficient detail to perform a control estimate to support AFE funding; fourth to develop project execution plans and schedules; and last to develop an MTO style control estimate with allowances provided for unknowns and soft areas in the design and execution plan.

Id. at 1-2.

970. The document also finds that there was excessive Owner involvement which resulted in project inefficiencies. Further, it finds that the cost trending system is inefficient since it only tracks design changes and not all other project cost trends. Tagging methods are inappropriate. There is $1 million under-estimate of SCADA software development. The fire and gas design in existing pump station facilities is still under development. Proper scoping and funding of PS1 Chiller revisions is not in place. The present work plan for the Start-Up Team does not complete all activities necessary to provide a fully functional pipeline. The execution plan does not complete RCM activities sufficiently in advance to support the optimal procurement of operating spare parts and full development of preventive maintenance procedures. *Id.* at 2-3. Among the risks to timely completion it lists: uncontrolled delivery of numerous drawings and revisions ("river of drawings") will impact efficient construction and FCO, unproven pump motors may experience multiple motor failures during early operation and exhaust the supply of long lead spare parts. *Id.* at 3.

Risks Identified by Category - August 2005

971. This document enumerates a number of risks. For instance, it points out that SR project controls are not effective. Currently undefined scope is required to complete SR. Ex. AT-235. Additionally, it states that the SR organization is not aligned on forward plan, regulators are not aligned, SNC/Hinz engineering is further delayed, material deliveries continue to be late, fabrication or field installation contractors perform poorly, there is a shortage of craft and management resources, the SR security system scope (S020) does not provide full interconnection or operating requirements for PS-11, River crossings, or SOCC, original vision of SR simplicity is not being achieved and the workforce reduction plans were based on this vision. *Id.* at 2.

972. SR specific issues identified through Alyeska project assessment include: unknown design issues (expensive relief valve internal change-outs etc.), uncontrolled

20140227-3052 FERC PDF (Unofficial) 02/27/2014

delivery of numerous drawings and revisions will impact efficient construction and FCO, unresolved late software delivery problems, lack of logic diagrams creates significant problems for providing comprehensive FCO and facilitation of long-term maintenance and operation activities, as-built not completed on time to support new maintenance activities causing the new maintenance work group to create and maintain their own set of as-built drawings, unproven pump motors ("Serial No. 1") may experience multiple motor failures during early operation and exhaust the supply of long-lead spare parts, inability to get long-term O&M personnel on the program, Alyeska O&M bench strength in mid and senior management levels not deep enough, operational spares not identified, purchased and delivered prior to start-up, total pipeline O&M structure not in place at start-up; change-out of PS 9 relief valve trim dependent on isolation valves holding in order to avoid pipeline shut-down and proration. *Id.* at 2.

973. Related to cost savings the risks are: transition to new equipment and organization reveals future maintenance problems, decreased cost savings results from new requirements following OSCP studies; retained buildings increases maintenance costs and personnel needs; personnel assumptions not coming to fruition in light of maintenance needs (RCM); JPO intervention in de-staffing schedule; security posture challenged by agencies as inadequate. The document also points out that there are risks of integration, system performance, training, resource delays of new SCADA Control system. Additionally, SR design tagging issues impact startup, resources are unable to support old and new facilities simultaneously. *Id.* at 3. Finally, one entry indicates that the fire systems are not completely identified in AFE S020. *Id.* at 4.

August 22, 2005 Exxon Electrification Project Supplement Review

974. Another Exxon supplement review is dated by the chronology as August 22, 2005. Ex. SOA-206. In this document there is a current preliminary cost estimate and "more work is needed to finalize the estimate." *Id.* at 3. According to this exhibit, the engineering and procurement are 80% complete. Construction is expected to be completed by September 2006. *Id.* The cost overrun factor analysis states that: (1) "[i]ncomplete appropriation scope and design changes – 36% (lack of project definition at appropriation leading to significant scope increase; unforeseen regulatory-driven design changes; underestimated requirements for tie-in, commissioning, and start-up)"; (2) "[i]naccurate appropriation estimates – 34% (underestimate of construction man-hours and Alaska labor costs; underestimate of amount of revamp work required; lower than expected engineering contractor and fabricator productivity);" (3) "[r]ework and delays-18% (reliability and seismic driven design changes; motor design and vibration problems requiring significant redesign);" (4) "[h]igher material costs – 12 % . . ." (5) "[n]o significant deletions to offset higher cost." (5) "[p]roject Management and cost/schedule analysis needs immediate improvement." *Id.* at 4.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

August 24, 2005

975. In the decision support package for FM Supplement dated August 24, 2005, BP states that project cost growth and schedule delay can be attributed to three fundamental causes:

> 1) The level of definition at the end of the define stage was insufficient. The Engineering Management and Procurement Contractor, SNC Lavalin, was not equipped to staff, manage, engineer and cost estimate the project…
>
> 2) … Additionally, the project team was not sufficiently integrated with operations during project development.
>
> 3) Commodity and freight inflation contributed 10% to cost growth, …

Ex. SOA-11 at 3.

976. The document describes electrification and lifecycle upgrades as being managed by Alyeska under AFEs S020, S031, S033, A034, S036, S038, S040, C116 and Telecom (TBD).[490] This supplement is for an additional $195.6 million. *Id.* at 4. The document states that as of "August 1, Engineering is 90% complete; 90% of the materials have been ordered; a take-or-pay contract has been executed with the local utility to supply electrical power from the grid to PS 9; an agreement has been achieved with Prudhoe Bay Owners for back-up/supplemental power for PS 01; the electrical motor vibration problems experienced earlier in the project have been resolved; construction contracts have been let; fabrication of some 56 truckable modules and skids is underway; piling is in-place; and, Alyeska workforce reduction plans are being implemented. Remaining work includes; completion of module fabrication; module transport; field assembly and installation; indoor electrical and instrumentation hook-up; module interconnections; FCO, commissioning and start-up." *Id.* at 5. However, the project is expected to overrun sanction authorization by 90% (P75). Start up is projected to be delayed by nine-months, forecasted savings are not at risk except for delayed implementation. *Id.*

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[490] The document also states that there are other scope components that fall within SR but are encompassed in other related FMs. These costs are necessary to achieve the goals of SR or would have been required as lifecycle work in the absence of SR. "This includes FMs for PS5 Upgrades, Rampdown Station Upgrades, PS 12/ OSCP and LTO Capital. *Id.* at 5 n. 2. In the description of SR the document states that PS1, 3, and 4 use process natural gas received from North Slope producers for general fuel needs such as mainline pump drivers, power generation and facility heating. After SR, this fuel gas will still be used for primary power generation. *Id.* at 11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

977. The document states that project costs have increased and start-up has been delayed, "largely due to the compounding effects of insufficient project definition early in the project, poor contractor performance and ineffective project management.[491] At present, the Electrification project is nearing the end of Detailed Engineering/Fabrication and ramp-up from partial to full construction activities. The projects, and both FMs, are forecast to run 90% over-budget (P75) and will require supplemental authorizations to enable completion." *Id.* at 5. "Program progress, and subsequently, the realization of business benefits, is nine months behind schedule with forecasted start-up by end of 3Q 2006." *Id.* at 6.

978. The cost overruns were due to poor preliminary engineering estimates (underestimated cost definition at Preliminary Engineering $44 mm gross); changes in design during detailed engineering (development during detail engineering $29mm gross); commodity price inflation (commodity prices and freight $20mm gross); schedule extension (schedule delay $13mm gross); poor productivity ($12mm gross); lifecycle scope increases and contingency (added lifecycle scope under 5 AFEs $53mm gross).[492] *Id.* at 26. The document describes "Underestimated cost definition ($44mm): The program was originally sanctioned at a level that was believed to entail +/- 15% uncertainty in costs. Typically, a program of this size would not move forward until a larger percentage of detailed engineering was complete in order to reduce this uncertainty to +/- 10%." *Id.* at 26. Concerning loss of productivity the document states that the cost increases have been incurred since SNC-Lavalin, Hinz, required rework from "changed/evolving design, poor project management little/no SNC Corporate support and not adequately understanding the regulatory requirements for the State of Alaska. This is manifested in drawings being at unacceptable levels in order to receive required "Notice to Proceed" orders in a timely fashion. *Id.* at 27.

979. According to this document key areas of weakness were apparent, particularly in areas of cost tracking, forecasting and operational readiness. The PMT has added resources to perform scheduling and cost control, and transferred a seasoned Alyeska project manager into the team as the Construction Manager. In addition, actions are being undertaken to hire third party project controls expertise. *Id.* at 36.

980. Concerning project economics the document states that revised economics have been performed against a "better view" of the Base/Inertia case due to increased costs. *Id.* at 16. "This better view case incorporates some $46mm (gross) of higher costs phased over the life of TAPS." *Id.* Further it asserts that Electrification and Lifecycle projects were run as an integrated package in the original FM and continue to be

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[491] *See also Id.* at 16 and 20.

[492] This included funding for unanticipated safety enhancements to the control system that regulates the RGV and Main Telecommunication Unit control system or SIPPS. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

evaluated this way. *Id.* A secondary benefit listed is the booking of additional reserves and consequently it states if "the project is cancelled, these additional reserves will be at risk." *Id.* at 17. Further, if the project is cancelled a "regrets payment of $18.5mm (gross) will have to be made to GVEA. *Id.* At this time they had already missed the tax incentives from the 2003 Act. *Id.* At page 18 the document considers the affiliate producers perspective. To wit, it describes BP's equity in TAPS as 46.9% and its throughput share average is 39% over the evaluation period. "This is a cost reduction investment hence there is no sensitivity to oil price. Likewise, the project has limited sensitivity to variations in the future production profile. That is because the TAPS tariff is designed to recover costs regardless of the number of barrels such costs are spread amongst." *Id.* at 18.

981. Three alternatives considered are listed. Number one, stop the project. This is described as "pay all required and project cessation/demobilization costs; incur cost for lifecycle upgrades mandated by regulators; salvage purchased equipment and take a write-down; manage ensuing regulatory/political fallout and revert to the no-Electrification scenario. (NPV 9 loss of $139)." *Id.* at 19. Number two, pause the project. This is described as "cease all construction activities, store and weather-protect exposed equipment; reduce spending to the minimum level required to fully complete engineering and to develop additional assurance around the cost estimate; assume an additional 3-month to 1-year delay is incurred; additional bridging funding will be required. (NPV 9 loss of $26 mm.)" *Id.* Number three is to re-scope the project. This is described as stop the project and re-examine conclusions from conceptual engineering phase to determine if the hybrid option is viable (i.e., completely automate the system while continuing to use the Avon-driven pumps)." *Id.*

982. In terms of regulatory risks the conclusion is that significant "cost overruns have been realized due to misassumptions around regulatory requirements in preliminary engineering." *Id.* at 20. The document states that due to the cost overrun, there is a distinct possibility that the prudency of the costs will be challenged. It also states that based "on our latest assurance work, it is now clear that the project was always going to cost this much to complete; however, that was not fully understood at the time of the original FM." *Id.*

983. Concerning the Engineering Contractor the document states that the contractor performed poorly in terms of cost and scope control and was replaced by Alyeska project controls personnel. *Id.* at 21. To mitigate costs the document states the owners took a number of measures: created a TOG; four separate audits; System Dynamic modeling to assess cost and schedule, removal of control duties from contractor to Alyeska, and engagement of BP technical engineering authorities. Additionally, the replacement of Alyeska leadership personnel and restructuring of the program management organization. *Id.* at 21. Despite these efforts costs have increased and start-up delayed, largely due to the compounding effects of insufficient project definition early in the project, poor contractor performance and ineffective project management. *Id.* at 24.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

984. A number of items are listed as lessons learned. First, late involvement of Operations negatively impacted the project. *Id.* at 31-32. Second, "SNC has turned out to be largely incompetent at managing fabrication, forecasting costs (engineering, fabrication, construction), and project controls and the design quality was below expectations." *Id.* Third, the TOG Scope management efforts were largely ineffective. Fourth, additional scope was missed in preliminary engineering but discovered in HAZOP or Operability reviews. Fifth, some key recommendations from TOG were not accepted "due to weak Charter." Sixth, "SNC unfamiliarity with Alaska codes and regulations was a liability along with …PMT lack of guidance and management." Seventh, lack of integration between SNC design team and PMT led to numerous design changes (increased scope) that have significantly driven the costs higher. Eight, "Insufficient PMT capacity produced a reactive environment." *Id.*

985. The contracting strategy changed from sanction through preliminary engineering, from fixed costs bids to a current strategy of incentivized time and materials. "The current strategy ensures that cost risk continues to be a significant factor through the construction phase of the project." *Id.* at 32.

986. The organizational staffing will change. The pump station operators will be replaced by telemetry and automated station controls. *Id.* at 34. No significant reduction in OSCP staff will occur, but they will be deployed along the line.[493] *Id.* Pump station maintenance personnel will also be re-deployed through "regionalization" or maintenance centers. *Id.* at 35.

Email from A. Bolea - August 24, 2005

987. A. Bolea in an email dated August 24, 2005, explains what went wrong. Ex. SOA 369. He states that the engineering contractor lacked sufficient cost estimating experience in Alaska and performed poorly during execution. In addition, he adds that the unique requirements of regulations in Alaska were not fully understood by the project team "during the define stage of the project, particularly as related to retained buildings and fire protection systems." *Id.* Further, he noted that there were leadership issues. "At several levels the leadership and behaviors were inadequate. There was insufficient operations input during the define stage. The overall team dynamic within Alyeska was poor; knowledge that should have transferred between operations and the project team either did not occur or occurred too late." *Id.*

August 26, 2005 - AFE S020 Supplement 2

988. AFE S020 Supplement 2, dated August 26, 2005, requests an additional $168.131 ($145.336 million capital and $22.795 million expense) million for SR. Ex. SOA-65 at

[493] The new centers are PS 1, Galbraith Lake (PS 4), PS 5 and Fairbanks, Glenallen and Valdez. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

3.[494] This brings the total AFE amount to $434.554. The request funds electrification and automation at PS 1, 3, 4 and 9 (including control system upgrades). Activities at the Ramp-down stations, PS 5, 7 and 12, and other related work (e.g. SIPPS, retained buildings Fire & Gas Upgrades, OCC Simulator) is to be funded in separate AFEs. *Id.* Fire and Gas System upgrades, for retained and modified buildings, were moved to a separate AFE S041 even though they were initiated under the scope of AFE S020. The AFE states that certain improvements will be implemented. For instance, the SR project team will be reorganized and integrated into Alyeska, to be managed by an Alyeska executive. Additionally, more engineering oversight is to be provided at SNC Lavalin and Hinz in Edmonton. *Id.*

989. The AFE states that the need for the supplemental AFE is "primarily a result of suboptimal organization, insufficient upfront planning and inadequate scope definition at sanctioning, which resulted in an original AFE estimate that was never realistic or achievable. The requested supplemental funding is primarily due to more refined scope definition. *Id.*

990. The capital cost estimates have increased by 63% since Supplement 1. Several subjective factors are contributors to the increase. The accelerated schedule (fast-tracked since conceptual engineering due to regulatory deadlines and economic reasons) meant that the project was approved at the end of preliminary engineering and major equipment had to be ordered to meet the 2005 schedule. Detailed engineering uncovered several assumptions that had to be revised. *Id.* at 8. "Late engineering was the most prevalent cause of project delay. Design was not completed on schedule and materials were not ordered when needed." *Id.* The statistical cost analysis at preliminary engineering was highly inaccurate, and the contingency was inadequate for that stage of project definition.[495] *Id.* at 8. The "original cost estimates created during Conceptual

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[494] The previously approved total was $266.423million. Approval is requested at the upper limit $457.014 million ($392.438 million capital and $64.576 million expense) to allow for sufficient contingency.

[495] The draft of the section titled "Capital Cost Increase" in the AFE (Ex. SOA-65 at 8) is different. Concerning preliminary engineering costs estimates it states they were "thought to be better than they turned out to be, and were lowered further using a "value engineering" process and a subsequent statistical cost risk analysis. The "value engineering" process identified approximately $30 M in possible reductions, some of which were used to reduce the AFE estimate and later determined to be necessary. . . . The statistical analysis, which was prepared by SNC Lavalin, was severely flawed and created a false since [zic] of accuracy. The contingency in the cost estimate was less than 7%, which is a much smaller amount than what should have been included at that level of engineering. Only part of the contingency was approved." Ex. SOA 66 at 1. Another difference is that the draft states that it is now evident that the project will cost approximately 70% more and will take nine months longer to complete. *Id.* at 2. The

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Engineering and Preliminary Engineering were low, in some cases by more than 100%." *Id.* at 9. This was not discovered until May 2005 when actual construction bids began to arrive. *Id.*

991. Additionally, the document points out that engineering design is 90% complete (except for some instrumentation, controls and programming). According to the document the piling is complete, and modules are being fabricated. *Id.* at 4. All materials have been ordered, the majority of them are in Alaska, and the turbine generators are at the sites. The estimates include detailed plans, schedules and cost estimates from the construction contractors based on IFC drawings. Work at the Pump stations has begun. *Id.*

992. The document points out that detailed engineering did not start until after project sanction based on the 2005 deadline for completion. The original deadline for Fire and Gas upgrades was renegotiated to the end of 2006 based on SR. *Id.* at 4. Further, the document points out that during detail engineering it became "apparent that the level of scope definition at sanctioning was not sufficient." Additionally, it also became evident that the schedule and cost estimates were not achievable. *Id.* at 5. The new schedule is start-up at the end of September 2006. "That is a six month delay from the first supplemental AFE, and a nine month delay from the original plan. The cost estimate has increased by 63%." *Id.* "Two major Alaska construction contractors (VECO & AES PPC) have been employed to plan, estimate and implement the field construction activities. *Id.* " The expected savings have been evaluated to be higher than those described in the original AFE." *Id.*

993. Concerning the expense cost estimates the document points out that those have increased by 61% since Supplement 1. The factors that caused the increase are: use of contractor resources due to limited Alyeska resources, extended duration of the project, tasks being performed at overtime rate, under estimation of the magnitude of the task or duration, task or need not identified at the time of original AFE. *Id.* at 11. Scope changes are described at pages 12-13. Necessary work, not identified in the original scope design but now identified, was separated into lifecycle upgrade decisions (at the Owners' request) while some was integrated into AFE S020 supplement 2. This is listed on page 14.

994. There is a section titled "Restated Original Economics." It states that for comparative purposes the "current savings and cost forecasts were input into the original AFE economic model." The document states that the "restated indicators are approximately $31 million NPV and 13% IRR. *Id.* at 19. Relating to major maintenance

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numbers between the AFE and the draft are also different. The draft shows cumulative AFE as $387 whereas the final document states $375. An unexplained change in this record. So between the draft and the final document the numbers were lowered. Compare Exs. SOA-65 at 10 and SOA-66 at 4.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

savings they have been updated using updated costs estimates concluding that the previous Inertia case forecasts were low, which understated savings. For years 2015-2024 system average values were used. *Id.* at 21. The document notes that automation programming work is lagging which poses a risk to program schedule. *Id.* at 22. Material procurement is said to be relatively small, or 10-12% of total procurement costs. *Id.* Module fabrication is 40% complete. *Id.* at 23. The construction costs contracts are for reimbursable costs with a fixed fee (contractor overhead and profit with incentive to complete work at the lowest possible cost). *Id.* at 23.

Email September 1, 2005

995. An email from L.W. Porter dated September 1, 2005, lists as the causes for increased funding for the project the following: overall project under-estimation at AFE, inadequate integration into the Alyeska existing operations organization, failed primary EPCI contract strategy, and resulting project completion delay of approximately nine months. Ex. SOA-347 at 2. Remaining risks are listed as: "1) insufficient improvement in PMT and resources to manage multiple contractors and interfaces; 2) ineffective integration into Alyeska existing operations organization; 3)ineffective project controls to manage capital outcome, including scope changes; 4) fabrication and construction craft resource constraints during 2005 thru 2006; 5) technical start-up and commissioning problems while transitioning from the existing pumping units; 6) external stakeholder relations and/or disruption." *Id.* The email mentions the view of the author that there is a possibility of schedule slippage to 4Q 2006, and in the worst case 2Q 2007 and that the cost estimate does not include a cost risking specifically tied to any schedule risking. *Id.*

Emails September 6, 2005

996. By September 2005, SNC's role in the project had been significantly reduced. In an email from J. Haines dated September 6, 2005, this is characterized as follows: "we have reduced their role to the minimum level required to complete the project, keeping only those roles that are necessary, with Alyeska picking up the remaining work. For example, the construction management role and project controls role (i.e., cost and schedule) have been removed from SNC's shop and placed within Alyeska (with some 3rd party project controls support also being provided). However, since SNC Lavalin did the original design, they are still being used finish the final bit of engineering (about 10% to go), and they are being used as engineering support during the construction phase (e.g., to respond to design issues that can arise during construction). Likewise, SNC has a small remaining role with procurement – overseeing the delivery of materials for the project that were previously ordered by SNC Lavalin, and have not yet arrived on-site. Other than this, Alyeska is back-filling with their own personnel for roles removed from SNC Lavalin's shop." Ex. SOA-362.

997. An email from K. Fuhr, dated September 6, 2005, notes that the costs distribution prepared by Alyeska "still appears optimistic to us." Ex. SOA-347. It points out that the curve was normalized "indicative that Alyeska doesn't recognize a number of risks we

20140227-3052 FERC PDF (Unofficial) 02/27/2014

think are real." The email goes on to state that the schedule could slip to the first quarter of 2007 and "this schedule slip is low." It continues stating that Alyeska has not placed adequate funds to recover schedule if we start to slip (in their cost estimate). There is also critical concern with three additional areas: access to craft workers; issues driven by external stakeholders (fire marshal, JPO, employee concerns); lack of ownership, alignment and clear consistent decision making due to the major changes in Project leadership. *Id.*

Supplemental Finance Memorandum

998. In this document BP characterizes the project as an enabler to book more reserves. Additionally it points out that the engineering is 90 % complete. BP in the sanctioning memorandum for Supplement 2 stated that a key enabler for staff savings the regionalized spill response structure has received regulatory approval, has been achieved and is being implemented. Ex. ATC-332. Significant, it states that it is expected to overrun sanction authorization by 90 percent. "And, whilst start-up is projected to be delayed by nine months, none of the forecasted savings are at risk, other than delayed implementation. *Id.* at 2. It also lists leadership, scope, contractor selection and inflation as things that went wrong with the project. *Id.*

Email September 9, 2005

999. The SR PMT management was changed in September 2005. In an email dated September 9, 2005, A. Bolea agrees that L. Monthei should be the new Program Manager. He asserts his belief that the Program Manager should not be from an Owner company and that this would be a mistake ("inserting someone into that role from an Owner company would be a mistake"). Ex. SOA-378.

Management of Hinz – September 2005

1000. The evidence in this case shows that the other primary contractor Hinz was also going to be managed on a rotational schedule in Edmonton. Ex. SOA-363 at 2. However, by email dated September 13, 2005, M. Drumm questioned this stating: given the problems that we've experienced with rotational oversight in the past, I think we should strongly consider appointing a semi-permanent resource to stay in Edmonton full time . . ." *Id.* On September 14 M. Rocereta also writes a "rotation approach was used with SNC Lavalin. It failed. What leads you to believe that a rotational approach will work with Hinz? Ex. SOA-363. There is no evidence in this record showing that the SR PMT learned from previous lessons by permanently inserting project staff in Hinz's offices to provide direct oversight of their work and track engineering progress.

SR Materials - White Paper - September 15, 2005

1001. This document discusses a number of problems with materials (defined as procuring, shipping, receiving, staging and issuing of materials required to complete the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

SR project, including long lead items purchased by SNC and the materials required for day-to-day work by the installation contractors)[496] in the project. Ex. SOA-316. It assumes: that SNC is phasing down as design and engineering progresses towards completion; the required data can be recovered from field receipt paperwork; someone knows the big picture. *Id.* The statement of issue notes that VECO and PPC have not been functioning in a way that will ensure that the SR project will be successful. *Id.* at 2. It finds that there is a major disconnect among SNC, PPC and VECO- lack of communication, no SNC presence in the field and SNC non-responsive when you call them. *Id.* In addition, it finds that there are no clearly defined processes, roles and responsibilities; there is a lack of field procedures to govern what happens; it is tough to determine the priority for purchasing materials; no direct lines of contact of field personnel; electrical vendors are running short of materials (materials are not on the shelf as expected); no purchase order information to determine if what was shipped is what was ordered (cannot match materials on truck to what was purchased); no packing slips, mixed loads (compound problem). The findings include that there is no "clearly defined MOC process" and the reporting by SNC is inadequate (overall document control is non-existent with SNC). *Id.*

Email Conoco - September 21, 2005

1002. In this email from M. Reimer to D. Johnson, Conoco requests $40mm for the project. Ex. SOA-238. It describes how the project was sanctioned in February 2004, following completion of preliminary engineering and approximately 15% of detailed engineering. *Id.* The request represents a change in scope for the addition of PS 1 power generation facilities and capital funding of PS 9 power facilities. The document identifies the root causes of the cost and schedule overrun: schedule and cost drivers; project management processes were not adequate; changes to project scope occurred when regulatory and operational assumptions developed during preliminary engineering were proved to be incorrect; active engagement by the operations organization did not occur until late in project execution. The drivers to the project were identified. First, $11 million in bonus depreciation and tax benefits that would have been captured had the start up occurred before 2005. A late 2005 start-up would avoid premium field construction cost associated with a heavy Alaska winter facility start-up and cut-over. Regulatory commitments of $15 million in pump station fire and gas upgrades by the end of 2005, existed prior to the project sanction but these requirements were waived once project approval was obtained. *Id.*

1003. However, "[r]egulatory and operational requirements identified during conceptual/preliminary engineering were incorrect, most notable of which were those associated with existing facilities and interconnect with new facilities. In particular, during detailed engineering it was determined that facility assumptions related to fire &

[496] Ex. SOA-316 at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

gas suppression for the existing facilities were not acceptable to the State Fire Marshall. Existing facilities were originally planned to be open to the environment and operated "cold", however, the State Fire Marshall required these facilities to have fire protection, facility heat and other services. Meeting these requirements resulted in fundamental changes to the overall project scope." *Id.*

1004. The document goes on to explain other problems associated with the EPCM (Engineering Procurement Construction Management) contractor. These included retention of experienced project management as well as quality issues associated with delivery of engineering packages. "Project delays were experienced when critical equipment (Electric Motors) failed to pass vibration testing criteria; the ultimate solution resulted in modifications to module size and piling requirements. The project was hampered by the Alyeska operations organization's lack of active engagement, which was required to evaluate and understand the impacts of the added existing facilities work. Active and effective operations engagement did not occur until early 2005, late in the project execution phase." *Id.* at 1-2. "The cumulative impacts of the various drivers resulted in a cascade affect [sic] on material and equipment procurement, module fabrication and issuance of quality construction packages that ultimately led to the significant cost increases and schedule delays necessary for work required to complete the project scope. Cost and schedule implications were not fully understood until late 2Q 2005, when definitive field construction estimates were received." *Id.* at 2. The document describes changes that were initiated to try to solve the problems. *Id.* at 2. It also points out that the project management and controls necessary to complete the project are not realized. Further, the document notes that in 2006, there may be a skilled workers shortage which could further delay the project. *Id.*

1005. Conoco points out that "ConocoPhillips Alaska, Inc's 2005 budget does not contain sufficient funds for the anticipated increase in 2005 expenditures and will require $11 mm from Upstream to cover anticipated expenditures in 2005." *Id.*

AFE S020 Supplemental Funding

1006. Another undated Conoco document[497] dealing with the request for an additional $40 million (COP net) states that as of September 1, 2005, detailed engineering design was 90% complete, 90% of project materials have been ordered, all major equipment has been purchased, and module fabrication was 55% complete. Field construction crews were mobilized to 50% of planned peak to support module installation and facility inter-ties, overall construction was 20% complete. Ex. SOA-292. The analysis states that point forward metrics are robust in large part due to the sunk project costs and negative consequences of the cancellation/delay alternatives, but the metrics are less than at the time of the original funding. *Id.* "Upstream Technology has assessed the project cost distribution provided by Alyeska and concluded the Alyeska P50 request of $106 million

[497] Ex. J-2 at 42, dates this document as September 2005.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

net is optimistic and has recommended a COP net mean expected of $110 million. The root causes of the cost and schedule overrun are listed in this document: "[s]chedule and cost drivers; [p]roject [m]anagement [p]rocesses were not adequate; [c]hanges to project scope occurred when regulatory and operational assumptions developed during preliminary engineering proved incorrect; [a]ctive engagement by the Operations organization did not occur until late in project execution." *Id.* at 2-3. It describes how a Program Team led by seconded Owner employees was created to introduce "breakthrough thinking" processes to the project. *Id.* at 3. "The Team reported directed to the CEO, separate from the Alyeska operations and project organization." *Id.* The Team was responsible for project execution as well as delivery of operational savings. *Id.* "Established project management and control processes employed by their affiliate companies were not utilized and the hybrid process that was utilized proved to be ineffective." *Id.*

1007. Scope changes, "particularly those resulting from the addition of significant Brownfield scope, were not subjected to a rigorous management of change process to evaluate and understand the entirety of the impacts. Further, the magnitude of the additional scope required to address facility interconnect with retained buildings, particularly its significant Brownfield nature, was not recognized in time to add resources necessary to assure the EPCM contractors' ability to deliver timely engineering packages." *Id.* Additionally, the document points out there were project delays resulting from the electric motors failing to pass initial vibration testing criteria, "the ultimate solution resulted in modifications to module size and piling requirements. The project was hampered by the Alyeska operations organization's lack of active engagement, which was required to evaluate and understand the impacts of the added Brownfield work. Active and effective operations engagement did not occur until early 2005, late in the project execution phase." *Id.* at 3-4. Further, it notes that cost and schedule implications were not fully understood "until late 2Q 2005," at which time definitive field construction estimates were received. *Id.* at 4.

1008. This document points out that the owner companies conducted peer reviews early in preliminary engineering and again prior to and during the original AFE preparation.

> All reviews indicated funding and contingency was adequate for early stage of project engineering and execution. All of these proved to be incorrect because the primary driver for the overrun, incomplete and/or inaccurate specification of the project requirements with regard to the new/existing facilities interface, were not reviewed by outside parties at the level of detail necessary to detect errors. The reviews assessed that the project had applied the proper procedures and Alyeska had provided sufficient resources to assure complete and accurate specification of the project requirements as compared to similar sized projects. The undetected failure was in the content of the information, under-estimation of TAPS regulatory oversight and a culture that is resistant to change. Similar failures occurred

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> during constructability reviews and other subsequent reviews related to onsite costs, particularly indirect costs for Alyeska provided housing, logistics, etc. and for tie-in work executed by the Alyeska project organization during a full TAPS shutdown. Further, the potential for significant commodity price increases of materials was not detected in the reviews because the reviews occurred before the escalation on material orders became apparent.

Id. at 5.

1009. An operations readiness review conducted in February 2005, determined that the Alyeska operations organization did not have the proper processes in place to accept the new facilities and were not fully engaged. *Id.* at 6. Mitigation measures involved assigning experienced individuals to key positions. In late July 2005, an Owner commissioned independent review was conducted. This review concluded that the execution plan needed improvement, improvements are required for the project management systems (safety, quality, cost and schedule), contingency for project costs needs to be larger, the proposed September 2006 start-up date is achievable but risky, "the risk associated with cost and schedule estimates are greater than currently characterized and the risk management approach needs to be improved", the project and operations organization needs improvement to ensure project delivery. *Id.* at 6. The document lists the root causes of project variations from original AFE: "suboptimal organization (structure, skill sets), significant changes to Project Plan (scope)" and "original assumptions were not accurate." *Id.* at 6-7.

September 28, 2005 - Pipeline Recapitalization

1010. In a September 28, 2005, document Conoco lists a number of root cause factors for the project's cost overruns. To wit, ineffective Alyeska leadership, suboptimal project team [inadequate planning, scheduling, incomplete scope, poor initial cost estimating (construction, regulatory requirements, poor contracting strategy], owner misalignment, schedule driven (cost savings, tax incentives & construction window, regulatory driven scope changes not challenged). Ex. SOA-483 at 2.

1011. In another document also dated September 28, 2005, Conoco lists the following root cause factors: (1) lack of owner alignment (Owner misalignment-BP driven to expense majority of project, concerns regarding losing BP support, alternative evaluation/PS1 Power (BP/EOM misalignment of GPA power benefit, misalignment kept APSC focus on owner issues distracted focus on project issues); (2) Alyeska culture (Alyeska resentment over Owner led project, no support from core operations, no visible APSC leadership to address conflict, need to gain consensus to the lowest levels, culture that leverages regulatory system to address concerns); (3) project management systems [APSC project systems inadequate to handle large SR project, Project Team direct report to CEO separate & equal to Operations to minimize scope changes, attempt to introduce new management systems to APSC/APSC rejected, default to hybrid, lack of experience

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of the project management team w/APSC culture, difficult regulatory environment, and handling large projects (fundamental mistakes-not collocating project team with engineering contractor, inadequate project controls (MOC-retained building team did not understand magnitude and impact of changes, regulatory process not challenged or alternatives reviewed due to incorrect assumptions on costs and concerns over schedule)]; (4) inadequate project estimating (poor information quality, incorrect scope premise, commodity price increases, significantly underestimated construction labor hours/start-up and commissioning costs); and (5) tight schedule [project management selection (3-4 month process), alternative evaluation delayed final AFE, PS 1 power misalignment, motor vibration problem, fire marshal commitment on fire and gas upgrades]. Ex. SOA-354 at 2-7.

Email M. Yaege September 29, 2005

1012. Evidence in this proceeding shows that Conoco also expressed concerns with the project. For instance, by email dated September 25, 2005, M. Yaege states that what has gone wrong with the project is based on: an improper management structure,[498] project management team capabilities, level of FEL work, quality of engineering contractor. Yaege concludes by stating that owner dynamics also had a part in the cost overruns (misalignment between ownership of north slope assets and ownership of TAPS, and between sharing of costs and sharing of capital). Ex. SOA-375 at 1-2. She also mentions that the SR PMT never raised concerns to the Owners' Committee about the lack of support from Alyeska management. *Id.* at 2. With regards to the FEL she states that "we moved the project forward on a challenging schedule in order to deliver some accelerated depreciation benefits that were only available if the project was completed by the end of 2005. We were also fighting a timeline laid out by the State Fire Marshall. .. While these pressures did not drive the decision to sanction the project, they did drive an earlier rather than later sanction date. We had completed 100% of the preliminary engineering, but only 10-15% detailed engineering at the time of AFE sanction. In addition, she states that K. Fuhr believes that SNC was ill prepared for the uniqueness of work in Alaska. *Id.* at 2.

Lessons learned 2005

1013. A lessons learned document is part of the record in this proceeding. It is titled TAPS Electrification Project-Lessons Learned with no date. The parties approximated the date to September 2005. The context of the document supports this. The document states that it is intended to capture the lessons learned from the supplementary FM review of the SR project and its cost increases. Ex. SOA-172. It describes how the project team was set up using people external to Alyeska. The project team "and the main stream Alyeska organization were kept separate to the extent that neither the project nor Alyeska staff considered the project part of Alyeska." Ex. SOA-172. The document asserts that

[498] The SR PMT was "an Owner manned team inside of Alyeska." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

as a result, the Alyeska staff did not cooperate with the project or transfer adequate people or knowledge to it. According to this document, this contributed to the problems of the project. The result was poor operational input, a lack of understanding of the regulations and regulatory environment and poor readiness of operations to start up and accept the project. It continues by pointing out that the Program Manger was unskilled for the size and complexity of the project. Alyeska had low level personnel coordinating with the PMT and their recommendations were not adopted. *Id.*

1014. Concerning sanctioning, the document states that the project was sanctioned "prematurely with an inadequate stage gate process." *Id.* Select and define stage were merged together and questions such as power supply were not resolved. "The level of definition at the end of define was insufficient. After sanction at least 2 major changes occurred. Power generation facilities had to be added at pump station 1 and all of the retained buildings had to have fire protection systems installed in them." *Id.*

1015. As to SNC Lavalin and Hinz it states that they had no experience with US standards or Alaska standards or practices. "They were supervised by low level rotational personnel and occasional [sic]visits from project mgmt. Even when problems occurred this continued. There should have been a mgmt. team of up to 10 people in those offices, …the project mgmr and his team should probably have been based there." *Id.* at 2. The regulations were not understood by the project team though they were understood by operations. The regulatory environment was not recognized or taken account of in the define stage work or even in the early detailed engineering work. *Id.*

October 3, 2005, Management Committee Meeting

1016. Slides from a management committee meeting for Conoco dated October 3, 2005, (TAPS Pipeline Recapitalization Funding Supplement Request) were admitted into evidence. In this document the project failures are attributed to the following: early signals ignored ("IPA 2/04 Report – low field costs/short construction duration); staffing mistakes (inexperienced project team, Alyeska engineering and operations separated from project, project team not co-located with engineering contractor); bad decisions (contracting strategy/Canadian engineering contractor without Alaska experience, established project management systems not utilized, equipment selection); schedule driven (tax credits, savings, fire and gas upgrades demands). Ex. SOA-381 at 6. Additionally, it points out that the suboptimal project team was not large enough to attract experienced Owner project "A" team. *Id.* at 12. Conoco recommends among other things, that Alyeska's project management systems be used. *Id.* at 8.

1017 An October 4, 2005, a document "TAPS Pipeline SR-Status" points out that the module delivery is not on track and this means that there will be more winter work and this adds $3-5M in costs. Ex. SOA-364 at 2. It is also critical of the "onsite management team in SNC and Hinz" stating "management personnel assigned on rotational basis not onsite full time." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Email October 5, 2005

1018. An email from J. Barrett sheds some light on the challenges of the project. After describing what was done pre-sanction the email states that the AFE was approved in March of 2004. "Long-lead materials were ordered immediately and detailed engineering began. The four major challenges experienced with this project included: (1) limited project definition at sanction; (2) underperformance by the engineering contractor; (3) difficulties with project management; and (4) challenges with stakeholder alignment." Ex. ATC-342. "Late decisions and insufficient engineering progress resulted in delays, and a lack of project definition yielded inaccurate cost estimates. Savings predictions, however, have remained on track. The estimate of major maintenance savings has increased." *Id.* "Operational readiness continues to be a concern, but the recent changes making this an Alyeska-lead project should rectify those issues. In addition, Alyeska has taken over project management from the engineering contractor and the project execution plan has been revised to include detailed plans from Alaska Construction Contractors." *Id.*

October 6, 2005 Supplemental Funding Endorsement

1019. The document describes the background to the project stating that it was appropriated at Gate 3 to accelerate O&M savings capture, bonus depreciation and avoid regulatory driven maintenance costs. Ex. SOA-174 at 3. The project was appropriated in March and initial construction started in July 2004. *Id.* The project completion is expected by fourth quarter of 2006. *Id.* at 5. The delays are attributed to weather, early design issues, regulatory requirements, material delivery and contractor performance. In the cost overrun factor analysis, Exxon attributes 40% of cost increases to incomplete appropriation scope and design changes (lack of project definition at appropriation leading to significant scope increases, …), 35% to inaccurate appropriation estimates (underestimate of construction man-hours and Alaska labor costs, underestimate of amount of revamp work required, lower than expected engineering contractor and fabricator productivity), and 15% to rework and delays (reliability and seismic driven design changes, motor design and vibration problems requiring significant redesign). *Id.* at 10.

Emails starting - October 27, 2005

1020. In a stream of emails, the email dated October 8, 2005, from J. Leone, states that we "continue to experience significant problems with non-operated major projects (. . . , TAPS reconfiguration, . . .). The note below and enclosed file describes some of the problems experienced with the TAPS reconfiguration project. All of the usual shortcomings can be found in this project: [s]chedule-driven, [m]is-aligned owners, "[jv]" operator, [i]neffective management and management systems." Ex. AT-274.

1021. An earlier email from the same day and source states that the TAPS reconfiguration project had four major deficiencies: "(1) [l]ack of project management

20140227-3052 FERC PDF (Unofficial) 02/27/2014

resources with adequate skill; (2) [p]oor estimating of the amount of work required to execute the project; (3) [t]he inability to identify, estimate, and manage change as deviations occurred; (4) [d]isappointing performance by the EPC contractor, and the lack of proactive management by the owners." *Id.* at 2. This email notes that "many of our managers don't have the experience and understanding to recognize what can go wrong with major projects. The result is that many don't have the skill sets to enable them to detect and address problems at an early stage. This was certainly the case with TAPS." *Id.* "We are placing a significant effort into educating managers across upstream on the roles that leadership plays into the outcomes of major projects…why projects fail and how leadership actions affect the outcomes of major projects. *Id.*

Management of Change October-November 1, 2005

1022. An October 28, 2005, email (from F. Krusen to M. Drumm) states that the new members of the PMT are not following the agreed MOC methodology "particularly with change in construction mode to winter work." Ex. SOA-485. At the very end of this email there is an entry "Systems Dynamics model: Greg advised me that a preliminary output indicated an April 2006 startup and a final cost of over $600,000,000; that is, a one-year delay and approx. $200,000,000 overrun from the current supplement. What I do not know is the likelihood of this outcome or recommendations on how to mitigate." *Id.* The response from M. Drumm, indicates that this is a BP forecast.

1023. In November 2005, L. Atteberry noted that TAPS SR's procedures for managing changes is flawed, by allowing construction contractors to start work on changes before costs are approved. Ex. SOA-323 at 2 (November 1, 2005). He also noted "the paradigm is shifting," "from schedule-priority to cost-priority, although Dennis's team is well aware of the Owner's concerns. Chuck Strub is convinced, for example, that executing work in winter, especially cable pulling, with its high overhead costs, will in the end save the project net costs by meeting their schedule for mechanical completion in 2006." *Id.* at 1.

Supplement 2 Approval- November 7-14, 2005

1024. BP approved the request up to $434,554,000 ($374,559,000 capital and $59,995,000 expense) on November 7, 2005. Ex. ATC-348 at 4.

1025. Exxon approved the supplemental request on November 9, 2005. It also requested supplements for AFE S026 (PS 5 Upgrades) and AFE S028 (Rampdown Station Upgrades). Ex. ATC-351.

1026. Conoco approved supplement 2 on November 14, 2005. Ex. ATC-353.

December 1, 2005

1027. In a December 1, 2005, email K. Hobeiche reports that a model's recent results forecast an additional $54 million in cost overruns (above supplement 2 or $434.5M) and

20140227-3052 FERC PDF (Unofficial) 02/27/2014

an April 2007 completion date (six months later than projected). Ex. SOA-541. He states that the model relies on historical engineering, procurement, fabrication, limited construction performance data to predict the future performance and outcome of the outstanding activities which are mainly field construction and commissioning. *Id.* Although he states he does not believe this is the right approach to predict the cost and schedule outcome, he points out that there exists a good and solid basis for cost estimating the outstanding construction and commissioning activities and setting an achievable schedule. "Because of the time & material execution approach being used the end costs can escalate and the schedule can slip if work is not very closely monitored and managed. Construction execution to date with a schedule slippage of about 18% and a cost overrun of about $6M occurring between August and November this year, does not provide confidence that cost and schedule will be met as planned." *Id.*

Lessons Learned December 2005

1028. A BP document dated December 2005, is titled lessons learned. Ex. SOA-202 (similar Ex. SOA-317). The document shows the fundamental "Learnings" or causes as how they could do the project differently. First, don't sanction a major brown-field project until detailed engineering is more than 60% complete. Achieve much higher levels of front end loading. Lump sum contracting strategy is difficult to achieve without very high FEL. Highly detailed resource loaded schedules must be in place to understand delay sensitivities. Project in current form likely not sanctioned with higher FEL. "Pilot (PS9)?/Smaller and phased (PS 3 and PS 9)?/Hybrid?" Second, use an EPCM firm with a proven Alaska track record. Place a full time BP engineering team in the contractors' office and do not rely on the contractor for project controls. Third, develop a more effective, forward looking project management organization and team with executive support. Including MOC. Fourth, address all stakeholder and commercial issues before sanction. *Id.* at 3. This includes finalizing commercial agreements before sanction. *Id.* at 20.

1029. Further the document notes that operations and engineering should be engaged in the project early on. *Id.* at 4, 30. Additionally, engineering should be 60% or more before sanction and scope should be determined early on. *Id.* Concerning the conceptual studies it states that they were done in secrecy with limited operations input. This created a lack of ownership. The document also points out that FEL was rushed and a fully loaded schedule was not available in an adequate form until after construction began. *Id.* at 10. As a matter of fact, at the bottom of the page there is an entry that states the schedule still is not fully loaded. *Id.* Additionally, it states that the target setting process did not identify that cost and schedule were unrealistic. *Id.* at 11. In addition, the document identifies as a primary driver of scope growth the brown-field aspects and that the scope was not adequately defined in preliminary engineering. *Id.* at 18. In the technical lessons learned it states, concerning motor vibration issues that the "existing technology for horsepower, however, first of their kind at 13kV and variable frequency." *Id.* at 32.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1030. According to this document, the early estimates were poor at the conceptual stage, with faulty assumptions, the retention of buildings introduced more lifecycle upgrades, tie-in and project management costs were underestimated and a proper risk matrix was not developed with respect to costs to properly evaluate costs. *Id.* at 36. At the preliminary engineering stage the conceptual assumptions were not fully validated or invalidated. Engineering was 10% and should have been 40% or more complete. The lack of Alyeska engineering and operations involvement early on caused PMT to miss brown-field and documentation issues. SNC's cost risk analysis was flawed and the retained building risk was not determined. At detailed engineering: the construction hours were underestimated, the delays from materials deliveries and drawing holds were not anticipated and the project was operating in recovery mode. *Id.*

Discussion 2005

1031. During this period the "train wreck" became more apparent. The Carriers were continuing to see cost overruns, the costs were exceeding the September 2004 estimates (shortly after construction started). In January 2005 they did an audit. Ex. SOA-383. In the same month, Tudor stated that the project has seen more than $100M or 44 percent cost growth from Gate 2 ($234 total estimate with no contingency). Additionally, he noted that the economics of the project from a return perspective have continued to decline as costs have risen. Ex. SOA-343. BP admitted by February 2005, that "the cost range was not adequately characterized" because "other urgent drivers . . . drove us forward with less detailed engineering than would normally be prudent." Ex. SOA-166. The fast track schedule adopted by the Carriers required design and engineering to begin even before the scope of the project was completely defined. "This resulted in a large amount of changes as design scope was finalized." Ex. SOA-257. Approximately, 12,800 drawings were issued after September 2005. *Id.*

1032. The incomplete design also resulted in "field work starting prematurely," before design and material procurement were complete. Ex. SOA-257 at 2. As a result, much of the design changes had to be done in the field because the "quality of the design documents was poor and required significant field changes." *Id.* As construction got delayed, impacts to construction crews resulted. *Id.* at 1. There were also many problems with the design of the control systems which required new resources to complete the engineering. *Id.* at 2. Additionally, to meet deadlines in the field, fabrication work was not completed at the factory and instead had to be completed in the field which is more expensive. Ex. SOA-308 at 2. Another complication was the decision to start implementation prior to receiving NTP (notices to proceed) from the JPO which contributed to inefficiencies in the millions and rework tied up critical engineering resources. *Id.* The "[c]onstructability reviews were inadequate" because "[c]ontractor comments on designs reviews were not incorporated into the final design drawings." Ex. SOA-257 at 2.

1033. Several estimates of construction costs were needed as a result of the changing designs and scope of work. Ex. SOA-257. In AFE S020 Supplement 2 the cost estimates

20140227-3052 FERC PDF (Unofficial) 02/27/2014

almost doubled due to inadequate scope definition at sanction. Capital costs increased from $212 to $375 million and expense costs increased to $60 million from $31.6 million. These increases can be directly attributed to the Carrier's decision to proceed on a "fast track" schedule and sanction the project based on incomplete engineering.

1034. Sanders testified as follows concerning the impact of the Carriers' decision to fast track the project: "[s]ubstantial post-sanction scope change and reworking required, including re-doing of drawings, changing contracting strategies in the middle of the project, adding new work, and ultimately disregarding the original construction execution plan in favor of creating a brand-new construction plan. These changes resulting from an initial lack of engineering study-which were exacerbated by the rush to complete the project by the end of 2005- that led to massive delays and cost increases reflected in AFE Supplemental Requests." Ex. SOA-542 at 80.

1035. The Carriers were concerned about the new electric pump drivers' reliability vis a vis the AVON/Cooper drivers they were replacing. Bolea raised questions about the reliability of the electric pumps after the project was sanctioned. Ex. SOA-216 at 12. The minutes of an Owners Committee meeting dated February 22-24, 2005, state: "[d]efine what additional testing will be required to validate the electric motors life expectancy, and develop contingency plan. John Barrett 04/15/05." *Id.* at 15. The electric turbines experienced problems shortly after being placed into service.

1036. BP considered the project a "train wreck" by March 2005. BPPA President A. Bolea and his associate M. Rocereta told a BP executive that they considered the project to be a "Train Wreck" and wanted advice on "how to mitigate going forward . . . including taking a 'pause' to get things back on track." Ex. AT-252. BPPA believed SR was a "performance bust" that was "clear to the Owners and regulators." Ex. AT-19 at 9, n. 17. This record does not include any evidence showing that the Carriers paused to evaluate the project to determine if they should go forward. *See* Tr. 3637:8-25 (Hisey testifying BP called for an assessment, and they internally had determined it was a train wreck). Hisey explained that in project management parlance the words "train wreck" have a clear meaning the project is "significantly off the rails" and that it requires some significant large scale intervention "stop, reassess, redirect." Tr. 3527-28:21-15. He also testified that you should declare it. Tr. 3937:8-20.

1037. Prior to sanction, the schedule was not resource loaded. In March 2005, BP confirmed this was a problem, reporting that, "individual project schedules [are] in a state of flux and in need of updating and resource loading. Ex. SOA-341 at 5. These deficiencies had not been resolved and in a December 7, 2005, assessment of Hinz it was stated that "very few resources are identified and assigned in the task details. Ex. SOA-248 at 2-3. A prudent utility manager would not have started a project without a fully resource loaded schedule.

1038. The Carriers argue that the project schedule was resource loaded and third-parties, IPA and JPO, reviewed and approved the content of the SR project's schedule. Carriers

20140227-3052 FERC PDF (Unofficial) 02/27/2014

IB 167-69. These assertions are not credible. The State points out that the Carriers do not dispute C. Sullivan's testimony that the schedule only contained approximately 400 activities to cover and define all engineering, procurement, construction, functional check-out, start-up and completion activities. Ex. SOA-1 at 182:9-11.

1039. Witness Oakland's testimony that the schedule was detailed and resource loaded is not given any weight. Upon close examination of the schedule it appears that the descriptions of the work to be done were vague.[499] The schedule does not provide any specificity as to what instrumentation should be installed at PS 1, nor does it identify the cable(s) that needed to be pulled, tested, and terminated at PS 3. The schedule did not specify what will be mobilized or surveyed at PS 4, or what needs to be competed to perform functional check-out at PS9. The description for the control system upgrade at PS 3 consisted only of six steps from December 2004 through August 2005, one of the steps was snow removal and survey. *Id.* at tab "SR Detail 12. 22.04-8.13.05."

1040. The evidence also contradicts the Carrier's claims that the project schedule was properly resource loaded. Exhibit SOA-340 at 5, states that a "fully loaded schedule [was] not available in an adequate form until after construction began (FEL was rushed). Additionally, contemporaneous documents show the projection was that a full resource loaded schedule was not to be completed until May 2007. Ex. SOA-342. This was four years after the project was sanctioned and approximately one and one-half years after the project was supposed to be completed.

1041. The Carriers contention that the JPO in some fashion approved the SR project engineering is contradicted by the record in this case, as Staff correctly points out. Thompson (Executive Co-Director of the Joint Pipeline Office) testified that they do not review for engineering design viability. "Well, our expertise is limited there, and to look at a project of this magnitude – and I think everyone understands how big it was – to assume that our small office –the state has two engineers and the federal government has two or three, maybe four. And to – and we're really not necessarily the right engineers for this type of review. I think everyone has to know that. What we have to fall back on in that case is the compliance with the stipulations and conditions of the right-of-way lease, . . ." The JPO is limited to monitoring for compliance with the contract and their interpretation of what they are proposing and the contract (right of way leases). Tr. 2600-01:11-6.

1042. BP acknowledged that the 2002 conceptual studies were done in secrecy with limited operations input. Ex. SOA-202 at 6. The Project assessment dated August 11,

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[499] For instance, "Install instrumentation [at Pump Station 1] (Ex. ATC-439 at tab "SR Detail 12.22.04-8.13.05"); "Pull cable, test & Terminate [at Pump Station 3] (*Id.* at tab "SR Detail 12.22.04-8.13.05"); Mobilize & Survey (at Pump Station 4)(*Id.* at tab "SR Detail 12.22.04-8.13.05"); Perform FC) (Functional Check Out) [at Pump Station 9] (*Id.* at tab "SR Detail 8.14.05-4.5.06").

20140227-3052 FERC PDF (Unofficial) 02/27/2014

2005, also found that the preliminary design phase of the project was completed improperly. The time frame was too short and the sequence of the work was not correct. Ex. SOA-219.

> The preliminary design phase of the project was completed improperly. The time frame was too short and the sequence of work was not correct. The proper methodology would have been: first to perform 4-5 months of detailed studies with knowledgeable Alyeska personnel to optimize the new design, identify all interfaces with existing facilities, optimize these interfaces, set design criteria, etc.; second to complete design control documents (i.e., P&ID's, electrical single lines, etc.) to allow initiation of the first level of design freeze; third to develop design sketches that depict the scope of facilities in sufficient detail to perform a control estimate to support AFE funding: fourth to develop project execution plans and schedules; and last to develop an MTO style control estimate with allowances provided for unknowns and soft areas in the design and execution plan. Considering the complexity of the program, the time frame for this effort should have been a minimum of 12 months.

Id. at 1-2.

1043. The Alyeska assessment also stated that one of the risks was "[u]ncontrolled delivery of numerous drawings and revision ("river of drawings") will impact efficient construction and FCO." Ex. SOA-219 at 3. Further it found that "[t]here still remains some uncertainty regarding the scope of related projects and interconnections with existing facilities." *Id.* at 1.

1044. Again in August 2005, BP explained that the "costs have increased and start-up delayed, largely due to the compounding effects of insufficient project definition early in the project." Ex. SOA-204 at 1. Additionally, BP noted that "[s]cope not adequately defined in preliminary engineering phase" and concluded that "[f]ull scope recognition could have fundamentally changed [the] project." Ex. SOA-202 at 18. In December, BP asserts that its estimated share $34mm of the cost increases was attributed to "inadequate definition/FEL." Ex. SOA-202 at 16.

1045. SNC, Alyeska and the Carriers all agreed that scope changes were the root cause of the delays and cost increases. As SNC noted in April 2005, most "significant among these is the very significant number of Design Change Notices (approximately 130) that have been generated by our personnel and approved by Alyeska. Many published studies, and our own prior project experience, have demonstrated that scope change of this significance will have a serious impact on both the cost and schedule of any project and particularly on a "fast track" project such as this one." Ex. SO-456. This is evidence of the poor level of definition following project sanction. Ex. SOA-425 at 47. The late issuance or revisions of project drawings is evidence that the project scope was not adequately defined. Over 100 percent of the project drawings were revised or issued

20140227-3052 FERC PDF (Unofficial) 02/27/2014

during September 2005 to May 2007. Ex. SOA-121. An internal audit in May 2005 pointed out that regional and cultural differences between SNC's typical engineering product and detail and Alyeska and Alaska industry product detail represents an area of conflict concerning the review and approval of the issued packages. The conflicts developed as a result of a lack of understanding of client preferences and regional contractor capabilities related to drawing detailing and narrative work instructions. Ex. SOA-216 at 61.

1046. SNC had no previous experience of US standards,[500] no experience of Alaska standards or practices,[501] and no track record of delivery in artic conditions.[502] The Carriers admitted that the SR PMT who oversaw the preliminary engineering stage was not the "experienced Owner project 'A' team. Ex. SOA-381 at 12. The State is correct that a reasonable manager would have recognized this gap in experience and implemented close supervision and oversight by personnel with TAPS and Alaska experience. However, the Carriers did not do this in this case.

1047. In May 2005 SNC was removed as construction manager and the responsibilities were shifted to Alyeska. Ex. SOA-216 at 20. Ex. SOA-216 at 33 states that the "project team has been struggling with SNC Lavalin's poor performance in project management for some time. The PS05 audit confirms these problems." Some changes were made in April 27, 2005. This document is dated May 2, 2005. The Carriers knew SNC's shortcomings since their hiring and there is no evidence in this record that they took any actions to mitigate these weaknesses (no prior pipeline experience, poor understanding of scope, SNC based in Canada and the fast track schedule). Anadarko is correct that based on these factors the Carriers knew that close supervision of SNC was necessary to successfully complete the project. As C. Sullivan testified: the Carriers fast-track schedule required "increased diligence on the part of the PMT to provide sufficient contractor oversight, especially in the areas of cost and schedule control. This usually is accomplished by housing senior members of the project team in the contractor's office to facilitate daily cost and schedule monitoring. On-site oversight also allows cost and schedule, as well as technical and execution issues to be identified and addressed immediately before they get out of control. Ex. SOA-1 at 187. However, the PMT did

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[500] Ex. SOA-172 at 2.

[501] Ex. *Id.*

[502] Ex. SOA-216 at 61. A document "Pipeline SR Mitigations Options" dated June 2004 by the Joint Chronology (Ex. J-2) states that SNC has no track record of delivery in artic conditions. The action column of this document states "[R]eplace SNC Lavelin as project management contractor." Ex. SOA-215.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

not follow these standard safeguards. As a result, it is found that the Carriers did not act as prudent utility managers.

1048. The PMT supervised SNC with low-level rotational personnel and made occasional visits to Canada, even after problems were identified. Ex. SOA-172 at 2. The September 2005, BP document stated that there should have been a management team of up to ten people at SNC's offices, and that the PMT should have been based there. *Id.* Conoco also noted that one of the project's failures was that the PMT was not "co-located w/engineering contractor." Ex. SOA-381 at 6. As C. Sullivan testified, the lack of proper supervision of SNC resulted in "late identification of cost overruns and schedule slippage, as well as being unaware, and later surprised, when they discovered that SNC has been overstating the percentage of engineering progress." Ex. SOA-1 at 187-88. A March 7, 2005, review revealed that the updated schedule done by SNC had the following problems: (1) could not verify that activities are tied to tangible work products; (2) one-third of the activities had less than ten days float: (3) many of the activities had negative float in the forecast; (4) engineering deliverable dates seemed to have been frozen regardless of resource constraints; and (5) unable to determine if completion criteria were set for each task or addressed in the schedule. Ex. SOA-247 at 12.

1049. In a management committee meeting on October 3, 2005, Conoco notes that one of the SR project failures was selecting a "Canadian engineering contractor w/o AK experience." Ex. SOA-381 at 6. BP also stated that "SNC has turned out to be largely incompetent at designing, managing the fabrication and forecasting engineering, fabrication/construction costs. Their unfamiliarity with Alaska codes and regulations has been a liability from the beginning." Ex. SOA-383.[503] Barrett testified that the Carriers should have known the differences between Canadian and U.S. engineering companies at the time of sanction. Tr. 5839:18-5840:1.

1050. Supplement 2 of AFE SO20, citing internal studies, found "that the need for this Supplemental AFE is primarily a result of suboptimal organization, insufficient upfront planning and inadequate scope definition at sanctioning, which resulted in an original AFE estimate that was never realistic or achievable." Ex. SOA-65 at 3. This exhibit at page 12, lists a number of items that were scope additions to the project and other design changes that increased costs. *Id.* at 12-13. If sufficient time had been allotted to scoping the project, these activities would have been included in the original AFE. Moreover, the Carriers at this point in time, were on notice that they should have stopped and reevaluated costs. The Carriers actions in this case were not the actions of a prudent utility manager.

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[503] The Carriers assert that SNC made some site visits to the pipeline starting in January 2004. Carriers RB 65. They cite various pages of exhibit ATC-813 in support of this. However, the cited pages show that a site visit for January 2004 was being planned. There is no evidence in this record that this actually occurred.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1051. It is found that the Carriers were unable to diminish risks by using lump sum contracts due to their accelerated schedule. On February 25, 2005, Larkspur estimated it would take over 500 hours, approximately four weeks, to prepare an estimate. The PMT concluded it was unreasonable to expect the five bidders to complete estimates for each pump station in the allotted time frame. Ex. SOA-458 at 2. Consequently, the PMT recommended that time-and-materials contracts be issued for the work orders. Thus, the risk of cost overruns was shifted to the Carriers. The contracting strategy developed during preliminary engineering evolved "since project sanction from fixed cost bids to a current strategy based upon incentivized time and materials. The current strategy ensures that cost risk continues to be a significant factor through the construction phase of the project." Ex. ATC-323 at 32. Note that the original estimate was 90 percent installation of new facilities based on lump sum contracts. At this point in time, it was too late to pursue lump-sum contracts and maintain the schedule. Ex. SOA-458 at 1 and 3.

1052. The evidence in this case shows that when the lump sum contracting strategy could not be achieved, the Carriers did not reevaluate the economics of the project. This was not the action of a reasonable utility manager. State witness Makholm testified that "[p]roceeding with electrification in the face of the market's rejection of that plan's basic contracting assumption was, in my opinion, the acme of imprudence. Either more complete project specification (so that contractors would be willing to bear such risks) or a change in the planning model (so as to compare a riskier Electrification Project to the other alternatives, such as Hybrid) would have been the reasonable course of action. Put another way, it was imprudent for the Carriers simply to yield to the immediate exigencies regarding time and materials contracts without a full review of the alternatives, thus absorbing the risk of overruns for an Electrification Project where management approval (sanction) had assumed otherwise." Ex. SOA-547 at 26:16-27:2.

1053. As stated by M. Reimer from Conoco, delaying the project beyond the original 2005 completion date would have prevented the Carriers from getting $11 million in bonus depreciation and tax benefits and approximately $15 million of projected savings through avoided fire and gas upgrades. Ex. SOA-238.[504] BP also admitted that the "project was moved to Detailed Engineering (March 2004) after sanction when preliminary engineering was believed at +15%, a higher level of uncertainty than would normally be accepted to move a major project forward. Acknowledged cost risk was viewed as acceptable given time sensitive drivers (i.e. access to accelerated federal tax depreciation benefits and avoided mandatory life cycle spend)." Ex. SOA-11 at 28-29. Exxon agreed that the "project had been appropriated at Gate 3 to attempt to capture the value associated with early implementation of expense reductions, together with bonus depreciation, which expired after December 2005." Ex. SOA-334. It is concluded that

[504] The Carriers in their Initial Brief (at 45, 138) downplay the role of the tax bonus depreciation benefits. However, as shown above the contemporaneous documents show that this benefit played a significant role in the fast track schedule.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

$11 million in benefits did not justify fast-tracking the project. Moreover, there was no cost benefit analysis of whether these benefits justified fast-tracking the project. Ultimately, these benefits were not achieved because the schedule was impossible to meet. The Carriers' actions were not those of a reasonable utility management.

1054. In July 2005, a project status report stated that "[s]cope of project has nearly doubled," causing the SR project to be "transformed into a crash program with an unrealistic schedule and turbulence." Ex. SOA-330 at 5. During detail engineering it became apparent that the level of scope definition at sanction was not sufficient. Ex. SOA-65 at 5. Thus, as determined above, the Carriers knew that the scope and schedule were deficient from the beginning of the project. By April 2005, the Carriers knew that there were a significant number of design changes almost immediately after the project was initiated. At this point in time based on a review of retained buildings fire and gas upgrades or "during detailed engineering it was observed by the design engineering firm that the controls for some process equipment were located in buildings slated to be taken out of service." Ex. SOA-104 at 2. However, Anadarko is correct that the Carriers knew the complexities of the automation work that needed to be done. The Bailey Report had done a detailed analysis as to what had to be done to automate the pipeline. Barrett testified that the Carriers should have known whether or not the control system was adequate for the project. Tr. 5833:12-15.

1055. The Carriers assert that the MOC process was "correct" even though it "experienced some problems keeping up with scope changes." Carriers IB 155 n. 68. As the State correctly points out, the project's MOC did not just have "some" problems keeping up with scope changes, it completely failed to keep up with the numerous scope changes that occurred during the fast-tracked SR project. As discussed above in the findings for the year 2004, the Carriers never implemented an effective MOC for the project.[505] In March 2005, A BP internal audit of SR stated that "[c]hange management process is deficient; will likely continue to cause changes and scope creep" and they admitted that this was one of the "[q]ualitative signs of trouble that [we] could have caught earlier." Ex. SOA-550 at 2. In June 2005, Rocereta from BP stated that the "scope management was largely ineffective because the missed scope mainly included things that were needed for the pump stations to function." Ex. SOA-383. This statement is corroborated by the Carrier's own documents. To wit, a White Paper dated September 2005 concluded that there was still "[n]o clearly defined MOC process. Engineers phone materials folks to "hold up" purchasing – field personnel never receive the word to go ahead when the issue is resolved, [d]rawing changes do not seem to be managed well – this seems to be more of a problem with PPC than VECO." Ex. SOA-316 at 2. Another document states that there are "currently change orders pending from the PS09 Piling project that are over three months old." Ex. SOA-285. In the AFE S020

[505] As noted above in October 2004, the TOG informed the SR PMT that the MOC as it was being applied is in direct conflict with the wishes of the Owners. Ex. SOA-460.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

request for supplemental funding there is a statement that "[s]uch changes, particularly those resulting from the addition of significant Brownfield scope, were not subjected to rigorous management of change process to evaluate and understand the entirety of the impacts." Ex. SOA-292 at 3.

1056. The fact that drawing changes were not well managed had a significant impact on the contractors in the field. For example, D. Hisey testified that "contractors were mobilized to do construction work, begin installation, and the drawings weren't there. The drawings that were there were getting changed. . . the drawings were coming to them the day they were there, so they had to survey them, and then the drawings were changing. And so they literally were out there trying to drill holes and every day getting a redirection of where to drill the hole and what size pipe to use. So that is a simple but good example of you are mobilized, ready to build, and you don't have a design you are trying to build to. We are pointing out that's a breakdown in your whole project management control system and quality system, and that's going to cost you some money." Tr. 3543:5-23. This testimony is corroborated by Ex. SOA-316 at 2. Hisey's testimony in entitled to significant weight.

1057. The Carriers did put a MOC process in place, but it was not followed and was ineffective. For instance, in an email dated October 28, 2005, Cononco stated that "the new members of the PMT are not following the agreed MOC methodology. This same email asserts that Khalil would be willing to volunteer himself as "MOC controller" on assignment to the PMT. Ex. SOA-485. Thus, at this point in time the process that is in place is not being followed and the process is therefore, ineffective. As a matter of fact, Ex. SOA-364 at 6 states that a lead scheduler, lead cost controller and a lead change controller have not been appointed. These positions are necessary for the MOC process. The lack of a reasonable MOC process leads to costs overruns and schedule delays. The lack of timely and accurate project data prevented the Carriers from making informed decisions. State witness D. Sanders testified, that the "failure to follow a reasonable Management of Change process increases the number of design changes and re-works required, which leads to substantial schedule delays and cost increases. All of these, would be expected to, and did occur in this project." Ex. SOA-542 at 82:14-17. The absence of an effective MOC process also resulted in problems including the inability to prudently track records, because "[n]o one knows what to do with the records generated by the project." Ex. SOA-316 at 2.

1058. As F. Adams testified, the reason for a MOC process is to mitigate concerns relating to scope and cost growth by ensuring information evaluated by the project team is timely and accurate. Ex. SOA-275 at 54:6-19. Timely and accurate information allows the project team to make informed decisions regarding project planning, funding and scheduling, which helps ensure "a project is completed on time, and per the budget, without excessive changes." *Id.* at 55:1-3. Sanders testified that "[MOC] procedures are procedures put in place through each of the engineering management phases in order to control cost and schedule by coordinating tasks and controlling scope increases." Ex.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

SOA-542 at 81:7-9. Adams further stated that a MOC process is designed to "ensure that changes are properly evaluated to ensure the safety, health, and environmental risks associated from the changes are controlled and managed." Ex. SOA-275 at 54:9-11. In this case the MOC did not do this. It is found that the Carriers were not reasonable and were imprudent by continuing the project without establishing and effectively implementing a MOC process that was actually effective in managing change for the project.

1059. Barrett's testimony that "in every instance, the scope additions were evaluated using a management of change process"[506] is not credible. An MOC could not have been used "in every instance" if necessary components of the process, i. e. individual resources (personnel) and a clearly defined process, were not in place. This is demonstrated by the fact that in September 2005 a White Paper finds that there was still "[n]o clearly defined MOC process. Ex. SOA-316 at 2. This is four months before the expected completion. In October 2005 the TOG reported that the "new members were not following the agreed MOC methodology." Ex. SOA-485. Thus the SR PMT was not even following the agreed methodology.

1060. The Carriers also failed to manage the budget, due among other things, the ineffective MOC process. The Carriers assert that "[t]here is no substantial evidence, however, to suggest that the TAPS Carriers failed to act prudently in managing the project budget." Carriers IB 169. The State correctly points out that the burden is on the Carriers to prove the prudence of the costs they want to include in their rates. State RB 116, *see also* n. 479. Moreover, the evidence does establish that the Carriers did not act like a reasonable utility manager. For instance, Tudor, Exxon's President, admitted that the project did not have proper cost controls. Ex. ATC-27 at 40:8-11.

1061. The Carriers attempt to blame SNC for the mismanagement of the project's budget. Carriers IB 169. However, the Carriers selected SNC and did not adequately supervise it. SNC was allowed to manage the budget with minimal oversight. In a letter to D. Wright it is pointed out that the "SR Team originally assumed that SNC's cost control process was more than adequate and would not require significant monitoring by the SR Team." Ex. SOA-476 at 3. Owner Committee meeting minutes point out: "Michael Rocereta asked why the problems identified some time ago with SNC were not addressed earlier. John Barrett acknowledged that the SR Team waited too long in trying to get SNC to address the problems itself and should have gotten directly involved earlier." Ex.SOA-366 at 3.

1062. Other exhibits show that together the SR PMT and SNC were not able to manage the budget. "Poor project controls and project management skills by both Alyeska and SNC-Lavalin have been visible since early 2005. Mitigations have been initiated, such as moving project management, construction management, and overall project controls from

[506] Carriers IB 155 n. 68 (citing Ex. ATC-24 at 31).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

SNC-Lavalin's scope to Alyeska project management team. However, key areas of weakness within Alyeska have also been apparent, particularly in areas of cost tracking, forecasting and operational readiness." Ex. SOA-11 at 36. Additionally, it is found that the problems that occurred with SNC were foreseeable based on their lack of knowledge and prior Alaska experience. Ex. SOA-66 at 2. A BP project review concluded that the choice of SNC had been a major liability to the project. "Poor cost estimation, weak Alaskan engineering and poor project management controls has contributed significantly to the unexpected costs experienced to date. Future major projects should limit their engineering contractors to companies with a breadth of Alaskan regulatory and Alaskan design criteria experience." Ex. SOA-277. Their actions not adequately monitoring the cost control systems and SNC, were not the actions of a prudent utility manager.

1063. Anadarko is correct that Owner misalignment was a factor in the imprudent decision making. The integrated economics of TAPS are compounded by the fact that the upstream interests are not aligned. This leads to ineffective decision making.[507] BP recognized this in a Business Performance Review stating that the

> Owners Committee and owner staff have had a tendency to carry upstream issues into the TAPS arena which translate into owner misalignments and dysfunctionality from the perspective of Alyeska. Differing political agendas, risk tolerance and business drivers translate into confused and inconsistent direction. Personality differences have also contributed to a level of confusion for Alyeska. These behaviors have also served to diminish accountability and limit the effectiveness of the Owners Committee. . . ConocoPhillips has developed a shadow management network in Alyeska that further fuels divisive behavior. For a variety of reasons, the Owners have failed to clearly articulate a unified vision for TAPS (lack of strategic alignment), to set direction in a coherent fashion (detailed plan elements underpinning the performance contract), to articulate their objective for the organization (in the context of the plan) or to clarify the scope, pace or measures for organizational change initiatives. Additionally, the decision process for owners (voting) makes some needed changes difficult to implement.

Ex. AT-19 at 7 (footnotes omitted).

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[507] An example of this is an email from A. Bolea dated April 30, 2004, he states: "The Owners indecisiveness this morning was a disappointment to me. Criticisms of us are entirely justifiable - and I say that without asserting that any Owner is wrong. I had hoped for a different outcome … I do not see a clear way forward. My intuition is that we will end up deferring PS1 electrification or eliminating it entirely. To be candid it always was marginal for BP and it's not going to take us much to back away from it." Ex. SOA-26.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1064. BP itself admitted that it has not clarified its strategy or committed to a consistent course of action in TAPS. Ex. AT-19 at 7-8. An email from C. Hatley of Exxon to D. Ahrens and J. Barrett from Alyeska, shows how the misalignment impacted SR. Hatley starts by saying that Exxon does not consider SR to be "very robust." He further states that there is a "significant disconnect between Exxon and the PL SR PMT as to the economic viability of the project, with any further scope additions coming close to driving the project over the edge." Ex. SOA-324. The email requests that Exxon's concerns be kept confidential (not beyond Alyeska management) and not shared with the other Owners.[508] *Id.* Conoco's Yaege confirmed this also. In an email discussing Owner company dynamics among other things, she states, that

> [I]t has historically been very difficult to reach consensus on some key TAPS decisions. In defense of the SR project team, they repeatedly asked for decisions on key components to this project and were not given those decisions in a timely manner. You were aware of the months and months we spent trying to reach resolution on the power source for PS 1. The decision we ultimately arrived at was suboptimal, but better than where either ExxonMobil or BP would have taken us . . . .
>
> This type of problem surfaces over and over again on TAPS. It is due in part to the misalignment between ownership of north slope assets and ownership of TAPS. It is also due to misalignment between sharing of cost and sharing of capital. Often the battles cost more in time than the debate is worth.

Ex. SOA-375 at 2.

1065. Additionally, Yaege gave other examples of misalignment and how it led to decisions that were not ideal. Tr. 4702:24-4703:8 (issue of injecting NGLs into TAPS) and Tr. 4707:9-17 (pumpability issue). Yaege also confirmed that "some of the owners were influenced by corporate interests. . . I mean integrated interests." Tr. 4703:12-16. *See also* 4703:12-16-23-4704:2. Hisey also testified that Owner misalignment issues created confusion at Alyeska. Tr. 3886:10-13. There is "almost complete dependency of the TAPS Owners on their affiliated and parent companies to build, operate and improve TAPS," [509] such that "all significant funding decisions for TAPS are not made by the TAPS owners, but by the affiliated parent corporations or upstream producer affiliates of each Owner."[510]

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[508] Hisey corroborated this. Tr. 3908:17-23.

[509] *BP Pipelines (Alaska) Inc. v. State of Alaska Dep't of Revenue*, Case No. 3AN-06-08446 CI, slip. op. at P 554 (AK Sup. Ct. 2011) (2011 Ad Valorem Decision").

[510] *Id.* P 69.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1066. After all, TAPS is not like an independent pipeline, which makes decisions only for the benefit of its pipeline transportation business.[511] As has been found by state courts, "TAPS was not built or operated for tariff income, but to monetize the vast ANS reserves of the producer oil companies by bringing those reserves to market." [512] Tariff income that the Owners earn for shipping another producer's oil is in addition to the primary value that TAPS has for each Owner – the shipment of that Owner's affiliated oil." *Id.* The economic impact of the tariff revenue is so insignificant that TAPS would operate "even if there was no tariff income at all." *2011 Ad Valorem Decision* at P 554.

1067. An example of the integrated economics'[513] impact on SR is BP's decision to proceed with additional funding for SR in supplement 2, at the same time it had labeled the project a "train wreck"[514] to preserve the booking of 63 million barrels of additional reserves by its upstream production affiliate, BPXA. If the project is cancelled the reserves are at risk. Exs. SOA 11 at 17, 22; SOA-386 at 2-3 and AT-15 at 3.

1068. Additionally, the Carriers obtain higher profits from independent shippers who pay the tariff rates or the tariff rate increases the barrier to entry by independent producers that pay the tariff rate either as a shipper or through net backs when selling their oil production. Ex. AT-214 at 16-17. In this case in particular, the evidence shows that the affiliate relationships led the Owners and their upstream interests taking over the SR decision making from Alyeska. Tr. 4148:22-25. Moreover, independent shippers were not consulted. Other upstream concerns influenced SR, such as obtaining bonus depreciation for the Carriers production affiliates. Ex. SOA-292 at 3; AT-214 at 20 and ATC-237 at 32. The TAPS integrated affiliates make decisions which not always are in the best interests of the regulated pipeline. For instance, the Carriers decided to continue to implement PS 1 to avoid a write off of costs already spent on SR equipment, and not because it was technically the best solution. Ex. SOA-574 at 5-6. *See* discussion below.

1069. The Carriers argue that Anadarko did not show that Exxon and Conoco were improperly influenced by considerations applicable to affiliated shippers.[515] However, as described above (P. 786) Conoco did consider producer matters at sanction. *See* ATC-

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[511] Ex. AT-1 at 17-20; AT-22 at 22-30; Tr. 240:18-241; 370:15-23.

[512] 2011 Ad Valorem Decision at P 554.

[513] The TAPS corporate families have already paid the costs of SR, including these costs in rates provides larger royalties and tax deductions for the production affiliates (they can deduct the tariff rate when calculating the royalty and production taxes to the State of Alaska). *2011 Ad Valorem Decision* at P 538.

[514] Ex. AT-252.

[515] Carriers IB 188.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

262 at 7, 11 and 18. Therefore, the Carriers contentions to the contrary are meritless. Moreover, the fact that one of the Carriers may not have acted improperly is no defense.

1070. BP did not share with the other Owners the fact that it was pushing for approval of supplement 2, so as not to lose its booked reserves for its production affiliates. Ex. SOA-11 at 17 (booking of additional reserves). This evidences the issue of owner misalignment which has plagued TAPS. The fact that the evidence shows this matter was considered at the time of sanctioning supplement 2 does not undermine Anadarko's argument that upstream benefits were part of the consideration on sanctioning SR, contrary to the Carriers' contentions.[516] Moreover, several BP decision documents show the 63 million barrels of booked reserves as a line item. The fact that no monetary value was given to this as the Carriers' contend is not given any weight *vis a vis* the fact that this was a consideration in the decision making. Ex. ATC-323 at 18 (same as SOA-11); AT-15 at 3; SOA-386 at 2. BP's President Bolea in his deposition admitted that the booked reserves were a consideration in continuing electrification. Ex. AT-21 at 4-5. Moreover, Ex. AT-14 at 3 characterizes "THE PRIZE" as "book additional reserves."

1071. In an Economic Evaluation Report and Point-Forward Risk and Cost Probability Distribution Analysis for AFE S020 Supplement 2, dated August 2005, Alyeska pointed out that there was only a 10 percent chance the Avon gas turbines would need to be replaced in the next 20 years due to degradation or obsolescence. Ex. ATC-326 at 15. Thus, the Carriers contentions contrary to this document are meritless.

1072. Around the time of AFE SO20 supplement 2, the Carriers reversed their 2002 decision and they turned over the project to Alyeska to complete. Thus, Alyeska is operating TAPS and completing SR (reconfiguring the control systems, adding electric pump drivers and making the new TAPS infrastructure work with the old TAPS infrastructure). M. Rocereta in his June 27, 2005, email states that Alyeska took over project controls away from SNC and are doing them internally. Ex. SOA-383. He also states that the Carriers decided to "change the project strategy from schedule driven to cost driven." *Id.* Anadarko is correct that at this point in time the Carriers knew that they were not going to realize the projected benefits that fueled the "fast track" schedule. Further, they also knew that one of the reasons for the cost increases was their decision to "fast track" the project prior to having defined the scope and completing engineering.

1073. The lack of integration of Alyeska operations with the PMT also created delays in the schedule and cost increases. For instance, the original assumption about the project

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[516] The Carriers in their brief cite to the testimony of Haines. Carriers IB 188. Haines' testimony is not credible. First, he played a role in BPXA booking of additional reserves. *See* AT-13 at 1-2. Further, this witness testified under oath that BPPA "had no direct employees of its own." Ex. BPP-6 at 4. However, in his revised testimony he testified again under oath that "BPPA currently has 12 employees." Rev. Ex. BPP-6 at 4. He did not explain this discrepancy. Thus, it is found that his testimony is not credible.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

being greenfield could have used input from Alyeska operations. Alyeska operations also would have understood the complexity of the pipeline regulations which were not recognized or taken account of in the conceptual or preliminary engineering stage or early on in detailed engineering. Moreover, this separation also gave the PMT *carte blanche* to advance electrification without ever having to design and estimate the cost of the solutions to the serious technical issues that would arise from integration with the legacy equipment. The transfer of knowledge from Alyeska took place very late when detailed design was advanced. Ex. SOA-172 at 2. This led to animosity. "The project and the main stream Alyeska organization were kept separate to the extent that neither the project nor Alyeska staff considered the project part of Alyeska . . . The general feeling of animosity between Alyeska and the project was not conducive to success. Ex. SOA-172; Tr. 3202:21-3201:15.

1074. At the time Alyeska took over the design was not fully developed. By April 2005, approximately 130 design change notices had been generated. Ex. SOA-456.

1075. A year after sanction the Carriers are questioning the long-term reliability of the electric motors and they are still determining the testing required to validate the life expectancy of the electric motors. Ex. SOA-216 at 12. This is the result of not having done adequate due diligence and studied the infant mortality issues prior to sanction. Another example of not having done adequate due diligence prior to sanction was the assumption of the time between rebuilds of the new turbines. They designed for 25,000 hours for a compressor turbine and 48,000 hours for a reaction turbine (power turbine) and built the maintenance program around these assumptions. Ex. AT-429 at 47. However, they have experienced a 50 percent reduction in fired hours." Ex. AT-430 at 23. Consequently, they have to change out the turbines more often. Roberts[517] testified that they have decided to overhaul the cores in an Alyeska shop in Fairbanks instead of shipping them to England to be overhauled by Siemens as originally planned. Ex. AT-430 at 25. It is found that the maintenance savings projections were not based upon any meaningful due diligence.

1076. Evidence of the ineffectiveness of project management is found throughout this record. For instance, one of the subcontractors reported that the disjointed nature of project scheduling "disrupt[ed] the flow of planned work" that resulted in "vast amounts of out of sequence activities and lag time (standby)." Ex. SOA-291 at 2. Alyeska reported "[c]onstruction crews asking for materials with 4-6 week delivery in 7 days." Ex. SOA-316 at 2. Significant and constant scope changes resulted in work not being completed in an orderly manner, leading to increased costs, wasted contractor resources, and an extended project schedule.

[517] Roberts, an engineer, joined Alyeska in 2000, he currently works in the low-flow studies group.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1077. The Carriers argue that many of the scope changes were the result of "evolving regulatory requirements and unforeseeable circumstances." Carriers IB 146. The State is correct that the Carriers do not cite a single regulation that "evolved." On the contrary, this record conclusively shows that what really happened was that the SR PMT had the wrong assumptions about the codes or the wrong interpretation of the fire and gas regulations. As an example an e-mail from Barrett sheds light on this matter. This April 26, 2005 "Keeping You Posted" email refers to the design changes for the switchgear. He starts out by stating that they have been engaged for several months, in discussions about the ABB switchgear (an essential part of the electric distribution system for the electrified pump stations). The discussions involved whether the switchgear, by itself, could provide a visible means of disconnect as required by the National Electrical Code (NEC). The disconnect is "absolutely necessary to assure safe energy isolation for people working on various parts of the installation." "Alyeska recently met with the JPO and the Alaska State Electrical Inspector and agreed that the ABB switchgear does not provide a visible means of disconnect as required by NEC. We decided to install separate switches to meet that requirement . . . We reached this decision after an extensive review of code requirements and issues raised by Alyeska employees and our regulators. I want to thank the individuals who continued to keep these concerns about a visible means of disconnect in front of us. Their persistence ultimately led us to the correct solution. While we originally believed we had the right, and safe, interpretation of the code, it is now clear we were mistaken." The email points out that there are other concerns about the SR design and construction work, "including a concern that some project personnel have been subjected to harassment for raising concerns." Ex. SOA-627.

1078. The Carriers also argue that there were evolving regulatory standards in the determination of which buildings could "go cold" as a result of SR. Carriers IB 146. The Carriers do not cite to a single "evolving" regulation. However, they do admit that there was a 30 year old document which was the agreement between Alyeska and the State Fire Marshal to provide fire suppression systems in specific buildings that the SR project proposed to abandon in place without fire protection. Ex. SOA-104 at 1-2. Thus, this was known to the Carriers for 30 years. Barrett testified that "[t]he fact that we received information very late in the project, that there was a commitment from Alyeska about maintaining the fire and gas systems in the buildings that had certain type of insulation," was one of the things Barrett had in mind when he wrote that "a lack of project definition yielded inaccurate cost estimates" on October 5, 2005. Ex. ATC-342.

1079. SNC's lack of relevant project experience caused it to make basic and critical errors including failing to recognize "cost uncertainties for increases related to regulatory environment/fire code requirements ($6.9m), hazop and operability, and installation contracts in 'Brown-Field' conditions," that "a contractor with more Alaskan experience could have anticipated." Ex. SOA-166.[518] In a letter responding to Alyeska's concerns

[518] *See also* Ex. SOA-66, noting that "[t]he statistical analysis, which was prepared by SNC Lavalin was severely flawed."

20140227-3052 FERC PDF (Unofficial) 02/27/2014

regarding their performance, SNC admitted that their status as a Canadian contractor had been a liability. "Significant work process differences have been identified between the ways Alberta and Alaska contractors work, a point neither ourselves nor Alyeska identified beforehand." Ex. SOA-456 at 2. Thus, as found above, the selection and supervision of SNC were not the actions of a reasonable utility manager.

1080. Barrett testified that SNC's cost control staff did not have the necessary skills to work on the SR project. Tr. 5837:4-8. A. Bolea, President of BP Pipelines (Alaska) Inc. expressed similar sentiments about SNC. "The engineering contractor, although highly experienced in pipeline automation projects in Canada, lacked sufficient cost estimating experience in Alaska and performed poorly during execution. Ex. SOA-369. Bolea also noted, "[t]he unique requirements of pipeline regulators in Alaska were not fully understood by the project team during the define stage of the project, particularly as related to retained buildings and fire protection systems. *Id.*

1081. To justify their selection of SNC the Carriers argue that unforeseen circumstances, an oil boom that created personnel shortages and the 2003 retirement of an SNC employee, Reg Pole, caused SNC's poor performance. These claims are meritless. The Carriers proffer no evidence of a connection between SNC's performance and these two events. Further, Pole retired in 2003, before sanction of the project, so the Carriers' could not have relied on his presence to justify the selection of SNC.[519] Ex. ATC-25 at 16:7-13. The selection documents show that SNC's "proposed lead has no pipeline experience." Ex. ATC-182 at 7. The bid review team also observed that "[o]ther team members are okay, but light on hours. Poor understanding of scope." *Id.* SNC's bid was ranked third in the two categories related to project management team staffing. *Id.* at 6. This contradicts the Carriers' contentions of Pole's importance to the project. Barrett testified that the contract with SNC did not provide that they would get specific employees. Tr. 5919:15-5920:10. Furthermore, the Carriers do not specify what effect the alleged shortage had on the project. Moreover, they do not explain why they did not adjust their schedule, if in fact, such alleged personnel shortages did occur.

Conclusions 2005

1082. The State argues that even with all of the reviews and the plans to correct deficiencies, problems continued because the Carriers did not have a firm grasp on the amount of work that had been completed, and they declined to stop the project and obtain an accurate understanding of the state of the engineering. For instance, they removed SNC but kept it to "finish the final bit of engineering (about 10% to go)."[520] The State is

[519] There is no record evidence showing that Pole was a factor in the selection of SNC.

[520] Ex. SOA-362. Hisey testified that he had recommended firing SNC after they repeatedly lacked progress. Tr. 3702-04:15-3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

correct that what they did not know and should have known is that this was not correct. In reality it was 70% complete at this point in time, as stated by D. Ahrens the SR business manager in April 2006 or seven months later.[521] At this point in time, they knew that SNC was inept at everything yet they did not stop to verify the accuracy of their numbers. They knew that the estimates were too optimistic and there were significant risks.

1083. BP acknowledged that sufficient engineering prior to commencing the execution phase of SR would have facilitated and informed the decision-making process: "[f]ull scope recognition could have fundamentally changed [the] project; choice of turbines-i.e. direct drive, maybe a phased approach/pilot, control upgrades rather than new equipment." Ex. SOA-317 at 16.

1084. What happened in this case borders on negligence. The Owners approved a project at preliminary engineering. This is contrary to their own protocols, manuals and well established industry practices. Compare, *Industrial Megaprojets, by Edward W. Merrow*, 2011, Ex. AT-273 at 202-203. In July 2005, they ramp-up from partial to full construction activities stating that they are near the end of Detailed Engineering/Fabrication. Ex. SOA-289. However, they knew that scope was a problem and costs were escalating and that they had done preliminary engineering in six months. They also knew that independent evaluators had deemed the estimates incorrect. The commencement of construction prior to completion of sufficient FEL was contrary to AMS-003 and standard industry practices.

1085. The Carriers learned that the project at sanction did not have sufficient FEL. They hired a contractor that did not have significant Alaska experience. They did not have a good handle on costs at sanction. At this point in time, with what was known by the Owners and what they should have known, BP characterizing stopping as a "dramatic option" is unreasonable and arrogant and it is not what a reasonable manager would have done. BP's statement "drove us forward with less detailed engineering than would normally be prudent" is considered an admission against interest that at the time of sanction they did not have sufficient engineering. This admission is used to corroborate the conclusion of lack of prudence (giving the Carriers the benefit of the doubt in the previous conclusions above). The emails from February 2005 show that they knew that the engineering was suspect, that major assumptions were wrong but they continued sinking money into the project, discarding the option to stop. For instance, in describing future projects and lessons learned from SR "we will arrive at sanction with a higher level of detailed engineering (60%)," using a contractor with a great deal of Alaskan experience and "we intend to pilot a key cost and schedule driver." Ex. SOA-166 at 1-2. A prudent manager would have known that the level of engineering was not in accordance with industry standards and their own protocols and thus it would have been

[521] Ex. SOA-371.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

clear that the project would have massive scope changes, cost overruns and schedule delays.

1086. The State argues that the imprudent rushed drive forward resulted in missed opportunities, such as failing to realize that the SR project represented a "technology step-out" because it was "never brought to [the TAPS Owners'] attention." The State is correct that the imprudent rush to finish the project resulted in lost opportunities. However, the example cited cannot be credited for this proposition. Certainly the owners knew they were rushing the project. They also knew they were dealing with custom made technologies. They had asked that the system be designed for a broad range of throughput. Ex. SOA-11 at 9. They also knew what they had requested from their contractors. So no weight is given to the statement that this was never brought to the Owners attention. They assumed that the motors were proven technology currently in use in the industry. "The guarantee of "proven technology" is slightly subjective with regards to choice of the linked electric motors and variable frequency drive (VFD) system." Ex. SOA-11 at 9. The August 24, 2005 document states, "in hindsight it is clear the largest component of the Electrification equipment, the motors themselves, must now be considered "serial number 1". *Id.* It is concluded that "proven technologies" for the motors was another incorrect assumption. A prudent manager would have done prototypes and further studies before embarking on the project. The hindsight wording in the August 24, 2005, document is not considered hindsight in the legal sense, their own lack of studies led to incorrect assumptions, which led them down the path of accepting the motors without sufficient engineering.

1087. It does not seem a valid assumption to increase costs for the Base/Inertia case based on cost overruns for an entirely different project. BP, the majority owner did not want to cancel the project because it had booked additional reserves based on electrification. Ex. SOA-11 at 22; AT-15 at 3; SOA-386 at 2-3. Additionally, $18.5mm (gross) would have to be paid to GVEA if the project is cancelled. The Owners admit that typically projects of this size would not move forward until a larger percentage of detailed engineering was complete in order to reduce uncertainty to +/- 10%. There are no reasonable explanations in this record why the owners decided to proceed notwithstanding that they knew engineering was not to the standard normally followed in the industry. "The risk for this was viewed as acceptable given the time sensitive drivers (i.e. access to accelerated federal tax depreciation benefits and avoided mandatory lifecycle spend.)" Ex. SOA-11 at 29. However, this assumption of risk was not reasonable based on the fact that they knew they were accelerating the schedule and thus the engineering, so the risks were much larger than accounted for.

1088. One of the drivers for the project was the depreciation savings. Once they knew they had cost overruns and schedule delays it was very likely these savings were not going to materialize. A reasonable manager would have taken time to reassess and reevaluate the economics of the project and given a time out to do proper engineering. They selected and ordered major equipment at the preliminary engineering stage. When

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the assumptions proved to be wrong, when scope was wrong, they had already committed to the equipment. They had embarked in a path of no return since they had already spent significant amounts of money. If automation programming work is lagging which poses a risk to program schedule how can cost estimates be correct?

1089. As found above, the SR PMT was not the "A" team. Ex. SOA-381 at 12. The leader of the PMT was the Project Manager. This position was filled by six different individuals throughout the project. Ex. SOA-275 at 140:3-4. F. Adams testified that this amount of turnover is not typical for a project of this nature. *Id.* at 140:7. The knowing selection of personnel with limited experience for a project of the magnitude of SR is not the action of a reasonable utility manager made in good faith. It is an action that is not in accordance with industry standards and the Carriers own standards. For instance, the first project manager had never worked with Alyeska or on TAPS and his only experience as a project manager was on three very small pipeline repair/replacement projects with a budget below $2 million. Tr. 5705:15-5708:10. By May 2005, the management of SR was so inefficient that M. Tudor of Exxon stated that "it is difficult at this time for the Owners to know whether the project is under proper control." Ex. SOA-366 at 3. In a lessons learned document dated September 2005 BP is critical of this project manager's performance and states that a "Program Manager with the appropriate skills and knowledge should have been appointed." Ex. SOA-172. Conoco agreed and states that lack of "Project Management resources with the required skills" was the number one deficiency of SR. As a factual matter, Conoco developed a management training program based on the management of SR to teach its managers "why projects fail." Ex. AT-274 at 2.

1090. L. Monthei was hired after Barrett. BP's B. Cartwright, at the time an SR Project Advisor, by email to BP President A. Bolea criticized the decision to hire Monthei. The reasons for this was his limited project experience and that he was not strong enough to do the job, in addition to the fact that he did not have "the seniority or stroke in the organization," and could be easily influenced. Ex. SOA-379 at 2. Later on L. Monthei's lack of experience would be blamed for the woes of the project. For example, in Conoco's review of Supplement 3, to AFE S020 it listed "Inadequate Project Management and Project Controls – New team established at Supplement 2 lacked large project experience,-critical team members removed, - change impact not recognized." Ex. SOA-209 at 9. Monthei was the Project Manager during Supplement 2. Ex. SOA-378.

1091. The lessons learned document also corroborates that the failure to "[d]evelop the very best project management organization and team" was one of the root causes of overspend. Ex. SOA-202 at 35. Conoco concurred with this assessment, stating project failures included a suboptimal, inexperienced and understaffed project team. Ex. SOA-381 at 6. The lessons learned document also determined that the IPA report was a "[c]hecklist rather than quality measurement." Ex. SOA-202 at 11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1092. The Carriers intentionally isolated the PMT from Alyeska's engineering and operations organizations. Exs. SOA-375; SOA-172. As the State points out, this exacerbated the issues created by hiring unqualified individuals on the SR PMT. For instance, Barrett reported directly to D. Wright, Alyeska's President and CEO, rather than being integrated into Alyeska's operations or engineering departments. Wrigth was a "secondee" from BP. Tr. 5687:9-12; *see* also Ex. SOA-292 at 3. "Neither the project nor Alyeska staff considered the project part of Alyeska." Ex. SOA-172. In effect, the SR PMT was "an Owner manned team inside of Alyeska." Ex. SOA-375. Additionally, all key positions, such as Pump Station Electrification Project Manager, SCADA, Telecom & Control Systems Project Manager, and SR Program Manager were filled by TAPS Owner seconds or Alyeska outsiders. Exs. ATC-24 at 6:8-11; ATC-166 at 1-2; *see also* Ex. ATC-24 at 6:1-2.

1093. The Carriers admit that they failed to integrate Alyeska personnel into the reporting structure of the SR PMT. Carriers IB 150. Consequently, the SR PMT did not engage Alyeska's subject matter experts who knew the pipeline best. As the State points out, this in turn led to significant deficiencies in project execution.[522] To wit, BP stated: "[n]eedless to say this caused immense resentment amongst the Alyeska staff to the point that they did not cooperate with the project or transfer adequate people or knowledge to it. Alyeska mgmt. [sic] deliberately kept the 2 apart, though exactly why isn't clear. This contributed to the problems of the project. Late and poor operational input, a lack of understanding of the regulations and regulatory environment, poor readiness of operations to start up and accept the project were the results." Ex. SOA-172. The PMT's isolation also hampered their ability to effectively deal with challenges as they arose, "[t]he project was also hampered by the Alyeska operations organization's lack of active engagement, which was required to evaluate and understand the impacts of the added Brownfield work." Ex. SOA-218 at 4.

1094. As stated above in the findings for 2003, SNC lacked relevant experience (no Alaska or TAPS experience). Notwithstanding the fact that the Carriers knew this they did not properly manage SNC. The oversight over SNC was inadequate. As D. Sanders testified, industry practice requires "close interaction with the contractors including embedding project management team personnel in the offices of the contractors, reviewing progress reports in-depth, and making changes as soon as problems arise." Ex. SOA-425 at 86:9-12. F. Adams testified that a "project manager should supervise and control its contractors by housing its own personnel in the contractor's offices to monitor and control the project . . ." Ex. SOA-275 at 124:17-19. He also testified that the SR PMT's failure to embed project staff in its contractors' offices was inconsistent with accepted project management practices, and was particularly egregious in a case where the owner knew that the contractor lacked Alaska experience. Ex. SOA-275 at 124:15-125:19.

[522] State's IB 66-70, 82-84 and 171-73.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1095. However, the Carriers used "occasional in-person visits and written progress reports to assess the projects' status. *Id.* at 124:19. C. Hatley of Exxon admitted this in an email dated September 9, 2004, he states, "there are no Alyeska project team members providing direct oversight in SNCs offices (SNC is in Edmonton, Canada). Ex. SOA-321. He was critical of this, continuing to state, direct "oversight is necessary to prevent scope creep…" *Id.* Cononco observed in October 2005, that the SR PMT members had yet to be embedded in the contractors' offices and noted that it was a "staffing mistake" to have the "[p]roject team not co-located [with the] engineering contractor." Ex. ATC-338 at 6; ATC-340 at 2. The supervision of SNC was done through "low level rotational personnel and occasional visits from project mgmt" this involved mostly monthly meetings and reviewing status reports." Ex. SOA-172 at 2. "There should have been a mgmt team of up to 10 people in those offices, indeed as this was the center of gravity of the project for over a year the project mgmt and his team should probably have been based there." *Id.*

1096. Additionally, SNC had very little contact with TAPS personnel. The PMT reported that it was not until months into the project execution that the "SNC Project Manager and Construction Management team toured the pipeline . . . to introduce themselves to pump station staff." Ex. SOA-7. The Carriers in September 2005, reported that there was "[n]o SNC presence in the field" and "that SNC [was] non-responsive when you call them." Ex. SOA-316.

1097. By April 2005, the Carriers faced the fact that the SR Project was in "a bit of a crisis . . . with SNC" because "SNC [was] not making their deliverables."[523] Ex. SOA-359. Additionally, within a month BP's preliminary analysis of the project found that "one critical measurement is said not to exist – SNC measures neither discovery of engineering errors nor design rework man-hours nor drawing revisions to correct errors..." Ex. SOA-325 at 3. As a result, SNC could not provide adequate data on costs, could not make its deliverables and was not capturing critical project information.[524] As a consequence, "delays in material delivery and engineering have affected the module fabrication schedule, and late submittals and changes to the pile design have placed that work in danger of slipping past the point [of] reasonability." Ex. SOA- 359. The lack of oversight and effective communication led to delays in information reporting. A white

[523] *See also* Exs. SOA-384; SOA-456; SOA-563; SOA-325 at 8; SOA-366 at 3; SOA-375 at 2; SOA-238 at 1-2.

[524] For instance, SNC did not report a change in work to be done which ultimately was discovered by Alyeska and resulted in changing the contracting strategy. Ex. SOA-458.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

paper shows that "[o]verall document control is non-existent with SNC" and there was "[i]nadequate reporting from SNC – the reports being provided do not have the information that is needed and in some cases the data is 90 days old." Ex. SOA-316 at 2.

1098. Once these things were on the forefront, a reasonable utility manager would have taken steps to remedy these matters. A contractor that was deemed, "incompetent at designing, managing the fabrication and forecasting engineering, fabrication/construction costs," should not have been allowed to manage the SR project for years after project execution started. Ex. SOA-383. The Carriers acted imprudently in this regard. The additional costs on the project due to the inadequate oversight of its principal contractors was shown in re-work, schedule delays, and confusion among the SR PMT staff. These costs should not be borne by the independent shippers. The Carriers contentions that SNC was closely and prudently supervised is not supported by the record.

1099. The same thing happened with the oversight of Hinz Automation. L. Monthei suggested rotational oversight of Hinz instead of embedding key members of the project team (one individual would be in Edmonton for two weeks and another one would relieve him for one week). Ex. SOA-363 and 364. This was opposed by M. Rocereta, BP's TAPS Team Leader, stating that this would be repetitious of the errors with SNC, questioning that this would not work with Hinz either. Ex. SOA-363 and 364 at 2. However, Rocereta's opinion was not followed and they went with the rotational approach. Ex. SOA-365. Hinz also performed poorly which resulted in schedule delays. In a review of Hinz in August 2005, K. O'Connell found that significant changes were needed in project management or the Carriers could expect "the schedule design deliverables to continue to slip and cost estimates to continue to rise." Ex. ATC-825 at 8. The document points out that Hinz did not have "sufficient incentive" for its staff to complete the project in a timely manner. *Id.* The minimum recommendation was that there needs to be an increase in project management oversight in Edmonton. The recommendation was to wait two weeks for Hinz to improve or the work should be shifted to "contractors more experienced in working with Alyeska." *Id.*

1100. The Carriers recognized their mistakes. For instance, Conoco stated that "[f]undamental mistakes-not co-locating Project Team w/Engineering Contractor." Ex. SOA-354 at 5; SOA-483 at 2. BP also stated that "[t]here should have been a magmt. [sic] team of up to 10 people in [the two key contractors'] offices, indeed as this was the center of gravity of the project for over a year the project mgmr [sic] and his team should probably have been based there." Ex. SOA-172 at 2. The State is correct that the Carriers' lack of appropriate oversight was inconsistent with industry practice and was not the action that a reasonable utility manager would have made in good faith, under the same circumstances, and at the relevant point in time.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1101. In their brief the Carriers now argue that David Roberts[525] was "the Alyeska lead embedded" in Edmonton from mid-2004 until mid-2006 "to oversee the control system efforts". The witness' written testimony states he was assigned to the control systems in late 2003 and he "relocated for almost two years to Edmonton, Alberta." ATC-945 at 1:19-22. He was a Project Engineer and in mid-2005 he became the lead automation engineer for all SR software. He does not testify that he was managing or overseeing Hinz. Livett in response to a data request stated that M. Veit (Operations Supervisor) and W. McBride (Electrical Engineer) rotated on a 2 weeks on/ 2 week off. Veit and Roberts traveled intermittently through the end of 2005 and mid- 2006, respectively. This evidence does not contradict the arguments from the State or Anadarko. Moreover, the Carriers cite a portion of Howitt's testimony but omit that he admitted that the project manager was not embedded in the contractor's office full time in a $42 million project. Tr. 4616:18-4617:8.

1102. As determined above, the SR PMT was not qualified to manage the project. The failure to hire qualified and experienced staff had a tremendous impact on the SR project's overall costs. BP "attributed 30% ($41mm) of the CAPEX ($137 mm gross) supplement to project organization and management issues that prevented us from recognizing costs before sanction. Ex. SOA-317 at 5, 7.

1103. Barrett testified that the SR PMT followed AMS-003, Ex. ATC-24 at 28:9-10. However, Conoco Phillips determined that the established project management systems were not utilized. Ex. SOA-381 at 6. Kevin Hostler, Alyeska's President and CEO, acknowledged that the SR PMT "chose to ignore Alyeska's established Quality Control and Assurance and Project Processes. Ex. SOA-380. Consequently, Barrett's testimony contradicted by record evidence is not given any weight.

1104. The Carriers admit that at least $21m cost overruns are the result of insufficient detailed engineering (FEL) at sanction (the costs range was not adequately characterized). Ex. SOA-166. They admitted that "urgent drivers around savings for avoided major maintenance, tax bonus opportunity and the need to replace aging equipment drove us forward with less detailed engineering than would normally be prudent." Ex. SOA-166. The Carriers admitted the cost overruns and schedule delays are "largely due to the compounding effects of insufficient project definition early in the project." Ex. SOA-289; SOA-202 at 16. "The level of definition at the end of Preliminary Engineering was not adequate to accurately predict costs and schedule, and the project was funded without enough contingency. The original cost estimates created during Conceptual Engineering and Preliminary Engineering were low." Ex. SOA-237 at 3.

[525] Carriers RB 65.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1105. They also admitted that a "lack of project definition at appropriation led to significant scope increase." Ex. SOA-174 at 10.[526] BP stated in July 2005 that "TOG Scope management efforts were largely ineffective because the missed 'life cycle' scope mainly included things that were needed for the pump stations to function." Ex. SOA-289 at 4. Exxon concluded that 90 percent of cost overruns are attributable to "[i]ncomplete appropriation scope and design changes . . . [i]naccurate appropriation estimates . . . [and] [r]ework and delays." Ex. SOA-174 at 10. Exxon also confirmed that a lack of project definition at appropriation led to significant scope increase. Ex. SOA-206 at 4. In a budget variance analysis prepared by Exxon it concluded that inadequate definition "affected the electrical area the most", particularly in the area of power generation and distribution. Ex. SOA-213 at 2. Conoco also cited inadequate project definition as one the SR challenges. Ex. SOA-205 at 5. Conoco listed incomplete engineering (only 60 percent complete vs. reported 90 percent complete), rework and scope changes as reasons for cost variances.[527] Ex. SOA-209 at 9.

1106. The documents construed as admissions of project details at sanction are considered corroboration of the conclusions above, concerning sanction.

1107. SNC claimed in May 2005, that there are "many contributing factors that have impacted the status of the project. Most significant among these is the very significant number of Design Change Notices (approximately 130) … Many published studies, and our own prior project experience, have demonstrated that scope changes of this significance will have a serious impact on both the cost and schedule of any project and particularly on a "fast track" project such as this one." Ex. SOA-456.

1108. Supplement 2, for AFE SO20 also confirms that the project was inadequately defined at sanction. The supplement concludes that it was needed due to "suboptimal organization, insufficient upfront planning and inadequate scope definition at sanctioning." The document points out that this resulted in an original AFE estimate that was never realistic or achievable. Further, it states that the supplemental funding is "primarily due to more refined scope definition." Ex. SOA-65 at 3.

1109. Even though the Carriers were aware in October 2004 that the scope should be frozen they did not take effective measures to address the problem. In the spring of 2005, scope was still not frozen and Alyeska also pointed out that there was still a "[l]ack of clarity and understanding of Scope inside and outside team" resulting in "[u]nrecognized change . . . without measure of impact of change." Ex. SOA-247 at 14. A BP assessment concluded in March 2005, that the SR project was an "underperforming

[526] *See also* Ex. SOA-11 (BP).

[527] Barrett told Conoco that a lack of project definition yielded inaccurate cost estimates. Ex. SOA-194.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

project continuing to suffer from the interaction of: late definition, scope creep, and design changes leading to delays and inefficiencies. Ex. SOA-341 at 4. Two months later, scope had grown by 50 % as "measured by engineering hours." Ex. SOA-325 at 2. During this time frame 130 design change notices had been issued. Ex. SOA-450.

1110. The Carrier's improper execution led to cost overruns and schedule delays. The Carriers have admitted that the scope kept growing due to inefficient FEL, there was a failure to implement an effective MOC process, the PMT was inexperienced and the contractors were not managed properly. The SR costs will be around $786 million dollars and the project will not be completed until 2014. The State is correct that this will be nearly a decade after it was supposed to originally (at sanction) and over $500 million above initial estimates.

1111. Anadarko is correct that the Carriers and their affiliates had integrated interests, such as maintaining reserves that had been booked which played a role in the decision making process of the Carriers. BP the largest shareholder in TAPS was continuing to advocate for electrification at Supplement 2, even though it had already determined that the project was a train wreck[528] in order to preserve the booking of 63 million barrels of reserve by its production affiliate. The August 24, 2005, BP Decision Support Package, the August 24 and September 6, 2005 BPPA Supplemental Finance Memoranda, state that by booking an additional 63 million barrels, BP "created a DD&A[529] improvement of about $0.20/bbl for the Alaska BU." Ex. ATC-332 at 3. *See* SOA-11 at 17; SOA-386 at 2-3; AT-15 at 3 (same as ATC-332). The three documents also state that "[a]t year-end 2004, BP booked an additional 63 mmboe of reserves (SORP) on this basis . . . If the project is cancelled, these additional reserves will be at risk." *Id.* A prudent pipeline operator would not continue to fund a failed project based on affiliate benefits.

1112. These documents also have the following language after considering three alternatives (stop the project, pause the project and re-scope the project (re-examine conclusions from conceptual engineering to determine if hybrid is viable)): "[On] a go-forward basis, economics strongly support continuing the project against all identified alternatives. Even if project start-up is delayed for an additional year, or if costs overrun by 30% over this request, either scenario would be more attractive than stopping the project. . . . Further, the hybrid option was previously dismissed in conceptual engineering as economically unattractive, and would not be able to accommodate future turndown needs. Resurrecting this option would place the 63 mmboe of reserves at risk." Ex. ATC-332 at 4; SOA-11 at 19. The Carriers made this statement notwithstanding the fact that there are significant cost overruns, leadership deficiencies, scoping issues and

[528] *See* Ex. AT-252 at 1, an email notes that A. Bolea (BPPA president) considered the project to be a train wreck.

[529] "DD&A" stands for depletion, depreciation and amortization.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

contractor performance issues. However, it is significant that the Carriers did not stop to analyze the economics of their alternatives. They did not do an in-depth evaluation of ways to optimize the benefits of cancellation and contrast that alternative with a more well-defined estimate of the cost and benefits of continuing. What they did was a one sided, point-forward economic evaluation. However, this evaluation also added an additional $46mm (gross) of higher operating costs over the life of TAPS to the no-Electrification case. Ex. SOA-386 at 6. The statement that the forecasted savings are not at risk is not credible. Ex. ATC-332 at 2. Thus, the analysis was biased towards the electrification case. Further, the IRR of the supplemental case had dropped significantly from the original FM (IRR 24.7% to 12.4%). Thus, it is concluded that the economics of the project were eroding but they did not stop to do a due diligence evaluation of the issues and economic evaluations of the situation. These are not the actions of a reasonable utility manager made in good faith.

1113. As Anadarko correctly points out, by November 2005, many of the economic benefits contemplated in the original AFE began to disappear. The one-time tax benefits were not achievable because the project could not be completed by December 2005. The fire and gas upgrades had to be completed on the retained buildings. Major maintenance expenditures were increasing instead of decreasing as a result of the integration process. Moreover, the likelihood of maintenance expenses going up had increased exponentially since the Carriers had to operate the legacy equipment an adequately staff the pump stations. In an email dated November 18, 2005, R. Lang (Alyeska's Mechanical/Rotating Engineer) reported the realistic expectations for staffing the pump stations. He states that most of the "engineering work at the stations will not even be impacted by anything S/R does, so the work loads after S/R will be no less than now, and likely will dramatically increase as a result of correcting numerous deficiencies in the S/R design that was not addressed by the project. I do not think there will be any way to avoid this reality, either now prior to S/R startup or later after S/R startup." Ex. SOA-167 at 2. The Alyeska Senior Discipline Engineer, P. Butter, confirmed this assessment stating the post-SR staffing may be understated. *Id.* at 1. Significantly, the Carriers were also aware that the detailed design of automation and control systems being conducted by Hinz Automation was approximately 35 percent complete. Ex. SOA-236. Moreover, there were many problems with design of the control systems that required Alyeska to intervene and bring in new resources to complete the engineering. Ex. SOA-257 at 2.

1114. An audit of the SCADA system was conducted during this time period. The automation director for Conoco participated[530] and reported that: the "SR project did not follow F370 design concepts and had only minimal input from OCC and SCADA support personnel;" "consequently, pipeline controllers had to redesign and rebuild the HMI navigation systems (PS9 had 6 SCADA screens under F370, now under SR has 280);" and "lack of coordination between SR Project and OCC resulted in a SCADA design that

[530] Ex. AT-408 at 13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

requires significant rework to be accepted by pipeline controllers as useful." Ex. AT-408. Roberts testified that in October 2005, the design of the control system for the SR project was not completed. Tr. 8716:7-10. Roberts also testified that the controllers redesigned and rebuilt the HMI navigation system. Tr. 8718:16-8719:1. It is concluded that the Carriers knew that the automation for the pipeline was not designed at the time they approved supplement 2. This was the main point of the Bailey Report, automation. A prudent utility manager would not have continued with the project until a necessary system had been well defined.

1115. It is also concluded that the Ownership structure of TAPS or the misalignment of Ownership interests can lead to suboptimal, untimely decisions with delayed communications to those who are in charge of management. The record also supports the conclusion that affiliate producer interests were a deciding factor in sanctioning and execution of the SR project. Owner misalignment and upstream interests were elements of imprudence at sanction, at approval of supplement 2 (BPPA's concern for its affiliate booking of additional reserves led it to push for additional funding for SR, notwithstanding the fact that the project at this point in time is considered a train wreck). Anadarko is correct, that independent shippers should not be required to pay higher costs due to Ownership misalignments and upstream affiliate interests.

1116. At supplement 2, the Carriers knew that the scope of the project at sanction was not adequately defined and cost were increasing. They knew the project would not be completed by December 2005, so they knew they would not get the tax benefits. At this point in time, the Carriers could have stopped and reevaluate the project. Since the economics of the project were marginal to begin with, with costs expanding and benefits decreasing, a prudent manager would have at a minimum stopped the project. The Carriers acknowledged that the costs of the project had increased. They were also aware that the supplemental AFE in the amount of $434.5mm had less than a [PRIVILEGED MATERIAL REDACTED] probability of being achieved." Ex. SOA-345 at 7. However, the "[o]ptimizations of cancellation issues were not evaluated; funding for these potential scenarios would be justified on a case by case basis, separately." Ex. SOA-65 at 16. Thus, the Carriers never studied the benefits of cancellation in detail. Instead, they simply listed the "major cancellation assumptions" in the AFE without further study. *Id.* Anadarko is correct that any "point-forward" economic study was a "one sided" study much like the comparison between electrification and hybrid. This decision is not the kind of decision a reasonable utility manager would make in good faith. Anadarko is correct that it was imprudent for the Carriers not to do an in-depth evaluation of cancellation and contrast this alternative with the more well-defined estimate of the cost and benefits of continuing.[531]

[531] The economic benefits identified in the original AFE were not going to be realized. The one-time tax benefits were unachievable since the project was not going to be completed by December 2005. Fire and gas upgrades had to be completed on the retained buildings. Major maintenance expenditures were increasing instead of

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1117. In November 2005, the Carriers were aware that the detailed design of automation and control systems being done by Hinz was approximately 35 percent complete. Ex. SOA-236. The original completion date was one month away and the automation design was not complete. Hinz worked for almost five years and was unable to provide a final design for additions to the SCADA system arising from the SR project.

1118. In mid 2005 the Carriers admit that the project was "transformed into a crash program with an unrealistic schedule and turbulence." Ex. SOA-330 at 5.

1119. The Carriers argue that the lessons-learned documents should not be used in this decision since they are hindsight. Carriers IB 178. Note that this decision did not consider the lessons learned documents at the time of sanction. These documents were considered for the first time in the time frame for when they were written or for the execution phase. Moreover, for this phase, they are being considered as admissions against interest and as corroboration that the previous findings and conclusions were correct. This decision in this regard is very myopic, to give the Carriers' the benefit of looking at the evidence in the light most favorable to them. Thus, they cannot complain that the lessons learned documents penalize them. Moreover, the Carriers represent *Northwest Pipeline Corp.*,[532] as an absolute bar to considering after the fact documents. This case does not stand for this proposition. As a matter of fact, the Commission used the "hindsight" document to conclude as to the men's rea of the company at the time of the action. *See* 92 FERC ¶ 61,287 at 61, 996-97 (As the General Counsel's memo also finds . . .).

1120. The evidence in this case independently from the lessons learned documents shows that the actions of the Carriers were not those of a reasonable utility manager. For instance, in July 2005 the Owner Project Review Team found that some of the root causes for the cost overruns were the sub optimal PMT[533] and the significant changes to the scope. Ex. SOA-292 at 2, *see* also Ex. ATC-318. Moreover, the evidence in this case, independent of the lessons learned documents, shows that the Carriers prior to sanction, knew that the scope of the project was poorly defined. In September 2003, Tudor sent an email to Yaege and Bolea stating there had been significant scope and cost growth between gates 2 and 3, which had not yet been explained. Ex. SOA-183; Tr. 4933:3-4934:12 (Tudor was concerned about the magnitude of the scope and cost

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decreasing as a result of integration. Major maintenance savings were suspect since they had to operate the legacy equipment and adequately staff the pump stations.

[532] 92 FERC ¶ 61,287 at 61,996 (2000).

[533] There have been six different program managers during the project. Ex. SOA-275 at 140.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

growth). In October 2003, the Hinz estimate increased from $37M (10/9) to $49 M (10/20) to $57M (10/24) in one month. Ex. SOA-220. This significant increase in automation costs was ignored by the Carriers. This is not consistent with the actions of a reasonable utility manager. Barrett testified that, at the time of sanction, he was "very clear" with the Carriers that engineering for the SR project was only 30 percent complete and they would have to expect some changes because of the uncertainty. Tr. 5805:13-25. The Carriers as experienced companies knew that these were significant issues. Thus, it is concluded that they knowingly assumed the risks not only of the project but of the prudence of their actions and of not being able to flow these costs through their rates as a result of a finding of lack of prudence.

1121. Anadarko is correct that the record supports the conclusion that the "lessons-learned" documents reflect things the Carriers knew and ignored. As Anadarko points out, they knew that the project manager lacked experience at the time they hired him. This was not a "lessons-learned." As Hisey testified, cost increases were likely to occur, this was something the Carriers should have known prior to sanction. The costs overruns were discovered with engineering[534] "and further project planning and scheduling," "all these things could have been exposed with more time in the upfront engineering phase of the project." Tr. 3930:14-18.

1122. The Carriers attack Hisey's testimony as not credible and unsupported revisionist history contradicted by his actions while at Alyeska, and his testimony about what occurred after he was gone is uninformed and biased against his former employer. They further blame Hisey for the failures of the project. Carriers IB 181. However, Hisey's testimony is supported by the evidence in this record.[535] Moreover, of all the witnesses in this case he was one of the most credible. Thus, his testimony is entitled to significant weight. Moreover, as Anadarko points out, whether the SR costs can be included in rates is not dependent on whether the Carrier's can blame their employees for the imprudence of their actions (the Carriers). The Carriers cannot pass the blame on to their employees in an effort to include the costs in rates. Hisey was not in charge of the SR project. Tr. 3294-95. The Carriers created their own PMT to implement the SR project. Ex. AT-230

[534] Note that by April 2006 Exxon did a detailed variance analysis that quantified the specific causes for the cost overruns. Ex. SOA-213, *see infra*.

[535] Carrier witness Flood described the sanction as "[t]he project team was handed a deadline and conceptual engineering cost estimates that were improperly used as benchmarks." Ex. ATC-344 at 1. This corroborates Hisey's testimony concerning the inaccurate cost estimates. Flood also described the cost estimates and probability analyses as "not realistic." Ex. ATC-344 at 1. Carrier witness Tudor also recognized early on that the cost estimate "included inaccuracies in original estimates, addition or modifications of project scope, increase in materials prices, rework and delay." Ex. ATC-27 at 39.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

at 16; ATC-24 at 9 and 5. Additionally, the Carriers tried to bypass Alyeska and its procedures during the conceptualization and implementation of SR. Tr. 4823:10-4824:2; 4824:3-9. Hisey's testimony was under oath and has not been directly contradicted. His expert testimony is his opinion based upon the information he has reviewed.[536] Hisey also had biweekly monthly conference calls and quarterly committee meetings with the owners. Tr. 3607. He also had weekly if not daily communication with the SR program manager, Barrett. Tr. 3026:15-24; Tr. 3855:3-3856:5.

1123. In testimony Barrett also confirmed that the Carriers should have known many of the causes for cost overruns prior to sanction. Tr. 5797-5816. He testified that the Carriers started the SR project even though they did not know the source of power for PS 1. Tr. 5800:8-22. Barrett also testified that at sanction he was "very clear" with the Carriers that engineering for the project was only 30 percent complete and they would have to expect some changes because of the uncertainty. Tr. 5805:13-25. He further states he told the Carriers at sanction that the project had "zero float" and required "flawless execution." Tr. 5806:1-6. Barrett agreed with the statement that "fast tracking" (implementation prior to final design) causes significant risk. Tr. 5806:7-10. Barrett states that he explained the risks to the Carriers, that the risks were significant, and that they assumed the risks. Tr. 5807:7-19. Barrett was aware that "as a project gets more defined" . . . the range of estimate becomes tighter." Tr. 5808:6-8. He agreed that the Carriers knew that if the engineering had been more complete, they would have had a more reliable cost estimate. Tr. 5807:9-17. Barrett also admitted that there was a failure on everyone's part to understand the complexity of what it would take to do the SR project. Tr. 5808:18-24. Barrett was aware that there were Alyeska operations people raising concerns with SR. Tr. 5809:15-17. Finally, he conceded that the Carriers should have known what was necessary to get the SR project done. Tr. 5815:16-19.

1124. Barrett also confirmed that the Carriers knew at the time that automation programming was so complex that he searched the world over to find someone capable of programming it, including someone in the Middle East. Tr. 5827:10-16. Further, Barrett testified that the Carriers went forward with the fast tracked schedule notwithstanding these complexities. Tr. 5827:16-19. Additionally, Barrett testified that the cost estimating of SNC was deficient from the beginning. Tr. 5828:22-24. However, the Carriers retained SNC throughout the project. Barrett also testified that a higher level of definition of the scope of the project would have reduced the level of uncertainty. Tr. 5832:11-12. The Carriers chose to begin execution with only 30 percent of engineering complete. Concerning the cost control system, Barrett testified that the Carriers should have known whether this system was adequate for the project. Tr. 5833:12-15.

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[536] Hisey has been involved in projects assisting Alyeska and the operation of TAPS. *See* Tr. 3811:25-3812:25; Tr. 3806:13-22; 3809:25-3810:6; Tr. 3813:21-3814:11; Tr. 3815:11-25; 3817:5-8. The fact that the Carriers' contacted Hisey to be a Carrier witness in the prudence phase in this case, belies the Carriers' contentions in their brief.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Moreover, Barrett acknowledged that large international companies, such as the Carriers' affiliates, with extensive operations in Canada, should have known the differences between the engineering product of a Canadian engineering firm and that of an American engineering firm, at sanction. Tr. 5839:12-5840:4. In addition, Barrett admitted that the Carriers should have known that the new self-contained modules were going to require significant cabling and wiring to integrate them with the existing systems. Tr. 5842:10-25.

1125. According to Barrett, the Carriers knew at sanction that there was uncertainty with the schedule and that it could be extended. Tr. 5849:21-23. He also stated that the Carriers should have known that high demand for particular skill sets results in a high risk of turnover and shortage for undertaking projects. Tr. 5848:24-5849:8. Barrett concurred that the Carriers should have foreseen that there are special challenges and the risks in doing an expedited project for a joint venture on a regulated pipeline. Tr. 5870:3-11; see also Tr. 3031:19-3033:16; 3781:13-19; 3871:7-20. Anadarko is correct that the testimonies of Barrett and Hisey confirm the conclusions in the lessons learned documents. Thus, the Carriers should have known that the decision to sanction the project was premature and accelerating execution prior to completion of final engineering would result in delays and cost increases. Exs. SOA-172; 202; 208; 211 at 9; 212 at 6 (lessons learned from successful electrification /start-up of PS9 & 3 integrated into PS4 planning); 213; 219; 226-227 at 8; 230; 292 at 2-3; 308; 354; 370 and 571 at 11, 14 and 17. It is therefore, concluded that the lessons learned documents are not hindsight.[537]

1126. One of the arguments the Carriers posit for the project's expenditures is labor and material shortages. The record is devoid of any evidence proving this. The State argues that assuming arguendo that there were these shortages, the Carriers failed to properly respond to them since they were well known at the time and the resulting cost increases were really the result of mismanagement. State RB 135. Carrier witness Oakland testified that the Alberta oil sands boom "began in 2004" and resulted in "a tremendous shortage of qualified engineering staff, especially in the period 2004-2008." Carriers IB 161-162. J. Crider, for the Carriers testified that the Carriers generally make forecast and

[537] Ex. SOA-121 at 9 (further engineering showed that previous supplement was based on 50 to 70% engineering instead of 90% as reported); Ex. SOA-171 (two primary reasons for cost overruns and schedule delays: unrealistic completion deadline; project sanction and execution before project design). Ex. SOA-205 at 5 (challenges: early AFE sanction driven by regulatory commitments-inadequate project definition, optimism of preliminary engineering estimates). Ex. SOA-206 at 4 (cost overrun analysis: incomplete appropriation scope and design changes-lack of project definition at appropriation leading to significant scope increase). Ex. SOA-207 (incomplete engineering was not in specs as reported, but in design errors, slowed construction work and caused rework). Exs. SOA-209-210 (incomplete engineering and inaccurate estimates).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

projections to determine worldwide labor demands. Tr. 5213:4-17.[538] The State is correct that the Carriers did not identify a single reasonable measure they took to respond to the shortage. They did not slow down the schedule to allow the engineering to be completed. They continued their fast-track schedule. Exs. SOA-459 at 2, SOA-240 at 2. Moreover, they did not adjust the risk analysis. The State is correct that the only conclusion that can be reached is that the Carriers did not undertake any measures to respond to the alleged labor shortage. The State asserts that a reasonable response to a labor shortage would have been to extend the project schedule and allocate the work among the existing resources. Further, the Carriers should have evaluated whether the "claimed shortage" would affect the economics of the project, according to the State. They did not do this. The Carriers made no changes to the project schedule and allowed scope growth to continue. It is concluded that these actions are not the actions of a reasonable utility manager.

1127. C. Sullivan testified that correcting for mistaken assumptions in the AFE S020 economic analysis, electrification would not meet the Carriers requirement for sanction. Ex. SOA- 545 at 3:14-4:6. Under his model, the NPV for electrification is negative $52.3 million and the IRR is 8.64%; which does not meet the Carriers' minimum approval thresholds for sanction. *Id.* at 4:4-6; and at 19. The NPV for hybrid is $97.8 million and an IRR of 19.72 percent. *Id.* at 4. C. Sullivan increased the project costs ($271 million) to reflect a more reasonable estimate after sufficient engineering; he also delayed the major maintenance savings ($73 million) and the O&M savings ($123 million) to account for a more realistic schedule and completion date and he delayed fuel, power and DRA savings ($2.3 million) to account for a more realistic schedule.[539] He also changed the schedule consistent with industry standards. He established 30 months from start of preliminary engineering to sanction (preliminary engineering and FEL). Ex. SOA-1 at 181. He also provided 30 months for execution, for a total of 60 months or five years from start of preliminary engineering to project completion. Thus starting from April 2003 (when preliminary engineering started) to April 2008.[540] *Id.* The State argues

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[538] *See also* Tr. 5847:2-6.

[539] Compare Ex. SOA-664 at 2 Row 53, with ATC-243 at tab "All-in" cell Y51 (Expense) + cell Y73 (Capital) and AFE S020 NPV Analysis with Ex. SOA-664 at 2, cell Y53 (Expense) + cell Y75 (capital). Compare Ex. SOA-664 at 2, Row 53 with ATC-243 tab "All-in" Row 51. Compare Ex. SOA-664 at 2, Rows 29-32 with Ex. ATC-243 tab "All-in" Row 30; and Ex. SOA-664 at 2, Row 79-80 with ATC-243 at tab "All-in" Row 76. *See also* Ex. SOA-722, SOA-664 at 1; ATC-789 "All-in Tax"; Ex. SOA-664 at 2; *see* also Ex. ATC-789 at tab "All-in."

[540] The Carriers' expert testified that C. Sullivan's schedule was too aggressive since it did not include any allowance for unanticipated problems that often occur with this type of project. Ex. ATC-34 at 11-12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

these changes are conservative and that he did not change the amounts of the savings assumptions.

1128. C. Sullivan started with the total SR budget as of July 2005 of $524.6. Ex. SOA-398. This is consistent with the Carriers admission that electrification was going to cost this much to complete but this was not fully understood until detailed engineering was substantially complete. Ex. AT-219 at 6. *See*, Ex. SOA-11 at 20. These costs would have been known by the Carriers prior to sanction if they had done sufficient engineering and FEL. *See* Ex. SOA-275 at 157-158 and SOA-546 at 15:6-10. By way of example, if the Carriers had done adequate engineering prior to sanction, they would have adjusted construction costs by realizing that the costs were underestimated due to the assumption that the project was primarily greenfield having underestimated the costs of tie-ins and other work necessary for brownfield.[541] Further, they would have factored in the costs to perform fire and gas upgrades.[542] Moreover, they would have realized the work could not be completed by 2005 and would have changed the completion date. Ex. SOA-546. C. Sullivan then added $1.4 million per month based on a 19 month extension (as testified to by the State's experts) and added that to the costs to come to $550.1 million as a prudent electrification estimate at the time of sanction. Ex. SOA-546 at 15-16. C. Sullivan's and F. Adams' testimony in this regard are given significant weight. The State correctly argues that the economics did not support sanction and thus electrification was imprudent.

1129. The Carriers IB attempts to focus on the procedures used by C. Sullivan to distract from his conclusions, or whether the "before-tax" or "after-tax" figures should have been considered. Carriers IB 100-01. However, Carriers' witness Dr. Toof admitted on cross-exam that C. Sullivan's use of after-tax figures was the result of his use of the spreadsheets Alyeska prepared for the economic analysis in AFE SO20. Tr. 7414-15. Additionally, Alyeska's internal AFE manual, (Dr. Toof agrees that it directs Alyeska how to prepare an AFE, Tr. 7416:3-6) requires use of after-tax figures. Ex. SOA-30 at 33, 53, 55; see also Tr. 7415-18. The Carriers' criticism of C. Sullivan's reliance on after-tax values ignores the fact that at the time of sanction Alyeska and the Carriers used an after-tax analysis and discount rates of 11 percent or higher. Exs. ATC-36 at 38:15, 42-45; ATC-262 at 5; ATC-269 at 2. Further, Dr. Toof's arguments against after-tax values is contrary to the main stated justification for fast tracking the project, which was

[541] D. Hisey testified that "there … wasn't a lot of work done around everything else . . . all the additional costs you are going to have, the structural, the cabling, the fire marshal issues . . ." Tr. 3279:20-23. J. DeHass stating cost estimates appear low by a large amount… There doesn't seem to be nearly enough included for engineering, site construction and all the other activities that must take place." Ex. SOA-21.

[542] They made assumptions related to fire and gas suppression … that were not acceptable to the State Fire Marshal. Ex. SOA-292 at 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

to obtain the tax benefits of accelerated depreciation. Ex.s SOA-257, SOA-11 at 28-29, SOA-238, SOA-334. As the evidence in this case shows, BP stated that the project was fast-tracked "given time sensitive drivers (i.e., access to accelerated federal tax depreciation benefits and avoided mandatory life cycle spend)." Ex. SOA-11 at 28-29. As the State correctly points out, Dr. Toof cannot credibly claim that a before-tax analysis is relevant when one of the "drivers" of the project was the economic benefits that could be obtained through tax benefits. Moreover, there is no evidence in this case indicating that any of the Carriers would have evaluated electrification based on a before-tax NPV, on the contrary the record shows that the Carriers internal analyses of the SR project were actually done on an after-tax basis. *See also* Ex. SOA-547 at 31:20-32:6.

1130. The facilities had to be placed in service by the end of 2005 in order to obtain the bonus tax depreciation. Ex. SOA-60 at 24. The evidence in this case clearly shows that even when problems arose due to the accelerated schedule, Exxon continued urging acceleration of the project to obtain the tax benefits: the "[p]roject should be accelerated to meet the 1/1/06 placed-in-service requirement to achieve the NPV bonus savings." Ex. SOA-240 at 2. C. Sullivan used a chart similar to the chart used by the Carriers in March 2004.[543] C. Sullivan explained that the figures would have been apparent if the Carriers had performed sufficient engineering on Hybrid and Electrification. Ex. SOA-545 at 3:14-20. The State is correct that a reasonable manager would have taken time to complete sufficient engineering on Hybrid and Electrification and made a choice based on a balanced decision. Ex. SOA-542 at 42:20-22.

1131. The Carriers argue that Sullivan's analysis is a hindsight argument. Carriers RB 77-79. In addition, they contend that his numbers are flawed in a number of ways: included $115 million of investment costs that were not part of Supplement 2 (the total cost of Supplement 2 was $434.5 million); eliminated $200 million of the major maintenance and O&M savings. Further, they claim that his adjustments are result-oriented manipulation of Alyeska's 2005 economic analysis. According to the Carriers the project at this point had favorable economics on a full-cycle and point-forward basis. Carriers RB 82.

1132. As shown above, and as further shown below, the Carrier's maintenance and O&M savings have been found suspect. Therefore, their economic evaluation of the project was skewed in 2004 and even at Supplement 2. C. Sullivan's analysis is given weight to the extend it shows what a prudent manager would have found in 2005. At this point in time, a reasonable manager would have seriously considered stopping or delaying the project. AFE S020 states that the project was approved on preliminary engineering and detailed engineering started after project sanction in order to meet the December 2005 deadline. At this point of time "detailed engineering is now 90% complete (except for some instrumentation, controls and programing)." Ex. ATC-327 at

[543] Ex. ATC-243.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

4. The statistical cost analysis at preliminary engineering were highly inaccurate, and the contingency was inadequate for that stage of project definition. *Id.* at 8. In the supplement they increased costs and they also increased the maintenance savings by $103 million based "on new information." Ex. ATC-327 at 21. The record does not show what this new information is. Likewise, total staff reductions now are 285. *Id.* at 20. O&M savings have also been increased. *Id.* at 19. So the same argument can be made about the Carriers numbers at Supplement 2, their numbers are result oriented. There is no underlying documentation to support the point forward evaluation of canceling the project. Assumptions of cancelation were provided at page 16 and estimated cancelation cost components were summarized at page 17. The economic impact of reclassifying capital costs to expenses per owner for cancelation were not evaluated. Project cancelation costs were prepared at a high level. *Id.* at 18. It is concluded that the cancelation alternative was considered at a "high level." This means that it was not an in-depth analysis and certainly one not sufficient to justify such a large expenditure.

1133. The Carriers statements that the savings had been reevaluated and are now "predicted to be higher" are not credible. Ex. SOA-237 at 3. To wit, in July 2005 Exxon lists an outstanding issue "the re-evaluation of project savings and benefits in an attempt to recapture economics lost with project cost overruns." Ex. SOA-200 at 10. Moreover, the evidence shows that the "original vision of SR simplicity is not being achieved and the workforce reduction plans were based on this vision." Ex. AT-235 at 2. It also states: "maintenance costs and personnel assumptions not coming to fruition in light of maintenance needs; JPO intervention in de-staffing schedule; security posture challenged by agencies as inadequate. *Id.* at 4. Therefore, the unsupported assertions of savings increases in this time frame are not credible.

1134. The Carriers argue that they mitigated problems. However, the evidence in this record does not support this. As will be shown below, the problems continued to plague the project and apparent "corrections" did not work, were not followed or new issues arose all directly correlated to the early imprudent decisions.

8. What happened in 2006

February 2006-Owners' review

1135. A TAPS Owner review was conducted on February 6-10, 2006. Ex. SOA-320. The Owners expressed concerns with Hinz and SNC. *Id.* at 5. They still have not completed automation design and there are turbine generator issues. *Id.* The main concern is that the cost and schedule baseline is continually changing. *Id.* at 7. The recommendation is to freeze scope and stop change (the culture of scope acceptance has to be stopped). *Id.* at 9. Other recommendations included, getting alignment behind a clear automation control philosophy and placing a full-time management team at Hinz, SNC and CSI. *Id.* at 11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

March 2006

1136. Record evidence indicates that in March 2006, the project is struggling with the proposed start up plan. E. Monthei writes an email on March 20, 2006, stating that he is concerned about starting PS 4 only two days after PS9. He believes this is not workable and that they will need as much time as possible between the two startups so they can take advantage of the lessons learned from PS 9. Ex. SOA-229 at 2.

1137. An email from D. Roberts dated March 21, 2006, states that there seems to be a disconnect, since the plan calls for start up of PS04 two days after PS09. He says that no one on the Startup Team indicated that they could support such a schedule. Ex. SOA-229. "From my perspective the schedule is still primarily construction driven and does not reflect a realistic plan for bringing the systems on-line.

1138. J. Howell also affirms (email dated March 21, 2006) that the startup cannot be concurrent since it would not allow for lessons learned from one pump to the next. *Id.* Additionally, he states that we "are not staffed to start multiple pump stations." Only one engineer is trained with program automation and control change oversight and he'll have to be present at startup and tuning. The same issue occurs with J. DeHass who has to be present for starting and initial running of the MLU's. The email concludes by saying that it is not realistic or practical to plan running MLU's concurrently. *Id.*

SR Project Status- March 20, 2006

1139. A draft letter dated March 20, 2006, from Tudor on behalf of the TAPS Owners Committee notes that several recommendations from February 2006, have not yet been implemented. To wit, "[f]reeze scope and stop change, [f]reeze a standalone control estimate and control schedule (based on the supplemental AFE estimate and schedule) then report against them, [s]et intermediate milestones, [c]onduct independent risk analysis of cost and schedule." Ex. SOA-606. Tudor continues stating that inaction in these areas has resulted in "additional design change and rework at the field level, as well as a lack of clarity on project progress." *Id.* "There is a growing concern on the part of the Owners that the Supplemental AFE will be exceeded by a significant amount." *Id.*

March 27, 2006 Forecast Update

1140. At this point in time there is a $29.7 million increase in the AFE S020 capital for the first quarter of 2006. They have now depleted the Unallocated Provision and contingency. Ex. SOA-225. The cost increases are attributed to the following: $3.8 million to engineering; $1 million for SNC to among others, finish detail engineering; $2.3 million (Hinz) for work to fill gap items missed during the Supplemental AFE estimate and poor productivity on major deliverables. Further, $1.3 million to a third party engineering for transferred scope from Hinz and filling gap items missed during supplemental AFE preparation. *Id.* Concerning engineering equipment, the total

20140227-3052 FERC PDF (Unofficial) 02/27/2014

reported is $1.7 million. Of this $1.3 is for Siemens, for settlement of seismic change orders on Turbine/Generator module construction. Another $1 million was to Precision Power for settlement of change orders from late SNC engineering design completion. *Id.*

1141. In the category of materials the change was $3.2 million. Of this $.5 million were for station control panel/unit control panel fabrication due to design changes and $.3 million for fittings and flanges due to design changes from the late stress analysis. In the fabrication category the settlement of change orders from late design completion mask 15,000 hours of incomplete work transferred to the field. The modules were needed in the field as major support components for pipe and cable tray.

1142. In construction the amount is $36.8 million, the effect of design completion as new and revised engineering packages and drawings were issued. "What is clear now is that detail engineering was closer to 70% complete when the estimates were compiled for the supplemental AFE in May 2005, rather than the 90% claimed." "Design completion accounts for $23.0M of the forecast increases in construction." *Id.* "An additional $4.0M is attributable to design correction and re-work by the construction contractors." "Support contractors and Functional Checkout (FCO) are directly affected by the increased volume of work and extended duration of many activities not completed as originally intended by the original execution plan. The effect of this is approximately $7.0M." *Id.* at 2.

1143. Freight and module movement added $2.8 million due to the fact that the module size was increased beginning in January 2005, module transportation in the winter requires more and different equipment. Additionally, more equipment and material components are being delivered separately rather than incorporated into completed modules. *Id.* There is a $ 10 million contingency in recognition of the risks and uncertainties that remain and that there is no other allowance to absorb unexpected occurrences. *Id.*

1144. The reporting of the increase in costs was untimely because: (1) the November refresh consolidation was incorrect (field work is charged to four AFEs and other AFEs were subtracted incorrectly from the contractors estimates) and (2) an incomplete Trend Log (the trend log was not reconciled to the forecast model during December or January and budget additions from the contractors were not included). These were the result of resource constraints in December and January due to the year-end accounting close and audit. *Id.*

March 30, 2006

1145. On March 30, 2006, BP has an update that states that costs are up $31 million over the February assessment. Ex. SOA-207. They state that what really happened is that "construction efficiency was low" in January and February and "cannot meet budget at" the "current pace." Further, the document states that incomplete engineering resulted in design errors and that the incomplete engineering is slowing construction and causing

20140227-3052 FERC PDF (Unofficial) 02/27/2014

rework. *Id.* The recommendation is to re-phase the project to stay within approved budget and explore de-scoping option at PS1. *Id.*

Exxon Reconfiguration Variance Analysis – April 1, 2006

1146. In an Exxon Reconfiguration Variance Analysis[544] there are a number of items identified as "Inaccurate Estimates/Funding Gaps. For instance, the list in this category includes: underestimate of tie-ins during shutdown; FCP/Commissioning by Alyeska; Telecoms SONET ring network; 12 hr versus 10 hr shift OT premium; additional inspection and survey costs; drawings as-building underestimate; additional field engineering support; Alyeska supplied fuel; additional camp costs; additional Alyeska oversight staff; Prudhoe Bay Tie-line; additional medics and security; other (inadequate definition resulted in too many simplifying assumptions and identification of issues and gaps). Ex. SOA-213 at 1-2. For design development, as described above the first item states that the electrical scope increased by three; piling scope; pipe rack steel (seismic and pipe stress); T/G's artic enclosure design and fuel heating; PS 3 and 4 back-up generators from 750 Kw to 2.25 Mw; additional VFD module fire walls; additional security cameras. *Id.* at 2-3. It also lists commodity prices and freight increases. *Id.* at 3. Additionally, it lists design changes: additional retained buildings; stiff shaft motor; additional Halon banks; additional pump station recirculation; pump module piping sizes; additional disconnect switches; fuel gas metering; pump module layout review; PS 3 pad expansion; cold restart contingency piping. The schedule delay lists: Alyeska project staff; construction management team; storage and temporary heating. *Id.* at 4. In terms of performance, rework, regulatory oversight it lists: SNC/Hinz eng productivity (80%); ANSI tie-in flanges replacement; response to JPO oversight (direct costs only); fabricator claims due to late eng. & material delivery; motor vibration. *Id.* at 4-5.

April 3, 2006

1147. L. Atteberry from Exxon writes to J. Ray on April 3, 2006. Ex. SOA-374. He notes that there are anomalies in reporting the anomalies (referring to Ex. SOA-225) *See* March 27 2006, above).

April 6, 2006 Email- Keeping You Posted

1148. On April 6, 2006 Alyeska's President and CEO sent an email to all employees concerning the SR implementation plan. Ex. SOA-376. The new plan is to finish PS 3 and 9 first and the Safety Integrity Pressure Protection System (SIPPS) and other critical systems at PS 1 and 4 which are required for start up. They are planning for the start of PS 3 and 9 in 2006 and PS 1 and 4 in early 2007. Depending on the progress with PSs 3

[544] This document is undated. However, the chronology dates it to approximately, April 1, 2006 (Ex. J-2).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

and 9, PS 4 may be started at the end of 2006. The reasons stated for the change are the continued challenges due to incomplete engineering or late design engineering, issues with turbine generators and resource constraints. *Id.* Late engineering design delivery challenges the ability to finish field construction and requires a significant level of field engineering work. This in turn impacts schedule and cots. Incomplete design scope makes it difficult to accurately plan field work and complete procurement as planned. Additionally, design changes after field contractors are mobilized results in increased costs, which can be significant if re-work is required. *Id.*

April 10, 2006

1149. The Business Manager of SR describes it as being in trouble in an email dated April 10, 2006. Ex. SOA-371. They are again projecting cost overruns. Again, the reason for this is that engineering is not complete. To wit, "the engineering that was touted last summer as 90% complete was more like 70% complete then and still isn't quite finished now." *Id.* "So they are looking at another supplemental AFE request." The email notes that the project is approaching 50% complete on construction work and about 2% complete on functional checkout. Salient is the following language:

> Complicating this will be the implementation of a revised execution plan. Seems the contractors can't find enough qualified craft to staff up four stations concurrently. Progress and schedule are lagging severely as a result. We are going to focus on two stations in the immediate future to consolidate the best of the staff and craft. As those stations move toward FCO, Commissioning, and Startup, the constructors will move those experienced crews back to the other two stations that we'll demobilize from now. This, of course adds all kinds of new risk elements into the cost, will definitely prolong the job, and ultimately cost more money. So we'll be working on a revised cost estimate.

Id.

April 11, 2006

1150. Another update states that the $30 million cost anomaly was due to engineering revisions issued in the field for construction. Ex. SOA-370. The document states that project controls have improved since August but did not detect the cost anomaly in February when the engineering revisions were issued. "What is clear now is that detail engineering was closer to 70 percent complete when estimates we compiled for the supplemental FM last year rather than the 90 percent that was claimed by the project team." *Id.* According to this document, there are four emerging issues which will impair construction: corrosion issues with the turbine generators due to manufacturer error; shortage of qualified labor in key crafts; inadequate depth of Alyeska supervisory resources for the scale of the construction activity; and limited bed space in the field. *Id.* Alyeska therefore recommended, and the Owners agreed, to slow the pace of

20140227-3052 FERC PDF (Unofficial) 02/27/2014

construction. *Id.* The revised plan is to focus on PS 3 and 9. When these stations are completed, the crews will continue to PS4 then PS1. Start-up is re-phased over September 2006 – June 2007. According to the document, this new schedule results in early delivery of the benefits from the pump stations that have the greatest cost savings PS 3 and 9. "Deferring PS1, in particular, will have the least impact on the project economics as it was the most marginal of all of the projects in the investment scope." *Id.* Note that the Owners are deferring further construction at PS1. *Id.* at 2. Also note that of "the $44 million annual saving objective for this project, $X million was for PS1." *Id.* at 2.

AFE S042 PS 5 Retained Buildings Fire and Gas Upgrades

1151. The justification portion of the document states that the work is being required by regulatory code and commitments to the State Fire Marshall's Office. Ex. SOA-108. This document is dated April 8, 2006. It reports that during 2000 and 2001 a number of code violations were brought to the attention of Alyeska and the Fire Marshall. A survey team listed a number of violations. Violations that presented immediate life safety concerns were remediated. Additionally, "Alyeska made a commitment to the Fire Marshall to bring all remaining fire and life safety systems into compliance with current code by the end of 2005. *Id.* SR planned to modify some buildings in ways that would have obviated the fire and gas upgrade requirements (declassified facilities) and to remove a large number of buildings from operation which otherwise would require fire and gas system upgrades. Avoided fire and gas system costs were attributed to the SR effort as savings.

1152. During detailed engineering a decades-old agreement[545] was "rediscovered" and it became necessary to retain and upgrade several systems that had been slated for removal. *Id.* SR preliminary engineering also identified several additional buildings that were planned to be removed from operation as part of the effort to simplify operations and reduce costs. *Id.* at 2. The SR engineering firm assumed that the buildings would not require power and any fire systems could be removed. "During detail engineering it was observed by the design engineering firm that the controls for some process equipment were located in buildings slated to be taken out of service. The Fire Marshal indicated that the fire systems would be required unless the building was truly being removed from operation and therefore not being provided with power." "This is in part due to the foam insulated metal clad panel issue . . . This resulted in retention of several buildings slated

[545] "During original pipeline construction foam insulated metal clad panels were used for exterior walls of the buildings. The panels used did not have the flame spread rating required for use as wall panels. During original construction Alyeska mitigated this code violation by agreeing with the Fire Marshal to provide detection and suppression systems in all areas where the wall panels were required by code to have the flame spread rating." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

to be taken out of service, and retention of their fire systems as well." *Id.* "Timely resolution of these issues was critical for sustained operations and to the interrelated scope of the reconfiguration effort. SR immediately began to design the fire & gas solutions for the "modified" and "retained" buildings. When the SR schedule was delayed, Alyeska requested and was granted an extension for these upgrades through the end of 2006." *Id.*

AFE S042 PS 5 Retained Buildings Fire and Gas Upgrades

1153. On April 12, 2006, an authorization for expenditures was created requesting $1.6 million funding for Fire and Gas detection and suppression system upgrades in the retained and modified buildings at pump station 5. Ex. SOA-150 at 4.

April 20, 2006

1154. Conoco provides an update dated April 20, 2006. It starts by stating that the project has several names, Pipeline Electrification, Pipeline Recapitalization. At this point in time Conoco owns 28.3% of the pipeline. Ex. SOA-428 at 2. Conoco admits that SR was sanctioned early with inadequate project definition or 15% engineering completed. *Id.* at 6. The challenges included: unanticipated regulatory requirements; underperformance of the engineering contractor (SNC) and organizational resistance (misalignment between project team and operations). *Id.* Further it points out that inadequate definition resulted in too many simplifying assumptions. *Id.* at 7. For instance, the electrical scope was increased by three, PS3 and 4 back-up generators from 750 kw to 2.25mw, additional security cameras. *Id.* Additionally, concerning supplement 2, it states that it was based on 70% complete detailed engineering and the risk contingency determination was not adequately made, the project management was not adequately staffed, supplemental cost estimate contained errors and the significantly strengthened organization did not have the experience to deliver the project. *Id.* at 8.

AFE S020 Supplement 3 – September 25, 2006

1155. An additional $80.3 million to complete the construction, commissioning, and startup of SR (for PS 1, 3, 4, and 9) was requested on September 25, 2006. Ex. SOA-63 at 2. This brings the total AFE amount to $514.9 million ($454.9 million capital and $60 million expense). This included electrification and automation at these pump stations including control systems upgrades. The reason for the additional funding is that "engineering progress was overestimated in the previous request (based on vendor information)." *Id.* at 2. The firms had asserted engineering was 90% complete (excluding field engineering and software automation) but it was really in the 70% range.[546] *Id.* at 6. Design engineering was not completed to the level asserted by the

[546] As a result construction started sooner resulting in lower construction productivity and slower progress. *Id.* at 7. Additionally, procurement of some critical materials was not complete resulting in construction progress delays. *Id.* at 7.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

engineering firms or in some cases there were design inadequacies.[547] *Id.* at 4-5.[548] Further engineering resulted in the identification of additional work, and this resulted in extended project duration. *Id.* at 2. Insufficient engineering quality resulted in significant amounts of field engineering corrections, which impacted both costs and duration.[549] *Id.*

1156. Again, this document claims that engineering (excluding existing field issues), procurement and fabrication are substantially complete. According to the AFE, PS 9 construction is 90% complete and the experience is incorporated into a new execution plan and final funding request for the other pump stations.[550] Pump station 9 is

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[547] Design elements were delivered late, which impacted fabrication and construction. To mitigate this, completion was transferred to the field which added costs and additional work to the field schedules. The FCO work that was planned to occur in the fabrication shops could not be completed, which compounded the impact of the delays. *Id.* at 7.

[548] In terms of "work details not included in the design and cost estimates: Swing check valves; SCADA/HMI/Remote Terminal Unit (RTU) equipment and software; Leading Edge Flow Meters (LEFM) and PIG, Ultrasonic and Coriolis flow meters; additional disconnect switches required by regulators; cold temperature cable testing required by regulators; Early Systronic replacement for SIPPS; PS 4 heating system; Fuel gas heater skids; Additional piling; steel and platforms (e.g. under-module steel and cable tray support to comply with N.E.C., switch platform additions, etc.); FCO of approximately 750 additional tags in turbine arctic enclosures; various vendor claims for late delivery of engineering information and resolution of design issues." Ex. SOA-63 at 4-5. Examples illustrative of design change: "substation design resolution by 3rd party; negative VAR generator design change; fuel gas system pressure increase; module resizing; reconciliation of turbine building and equipment packages from various vendors; transfer of work from fabrication shops to higher cost field sites in order to meet schedule issues; steel and platform design completion (e.g. PDC transformer platforms, switch platform additions); piling location changes; additional control system engineering resources to recover from schedule slippage and missing deliverables; extended project duration caused by these and other related issues." *Id.* at 5.

[549] This document points out that the "scope of AFE S020 and related AFEs *S036-Lifecycle Replacement, S041-Retained Buildings Fire & Gas Upgrades, S038-SIPPS* is being implemented from common construction work packages." *Id.* at 5. Thus, "costs are initially charged to S020, and then allocated to these related AFEs using cost estimates developed from construction contractor analyses. *Id.*

[550] On page 13 it states that PS 9 is 92% complete and PS 3 is 83% complete. *Id.* at 13.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

scheduled for December 2006 startup and Pump Station 3 is scheduled for mechanical completion in November 2006. However, the startup of PS 3 is not going to take place until May 2007 to diminish operational risks related to winter weather. Then PS 4 and 1 will startup in September/October 2007 (unless a better strategy is identified in the winter construction shutdown re-planning effort). *Id.*

1157. Further "programming for control systems was an area of high concern at the time of the previous supplement. Coordination between the engineering vendors was inadequate and the effort has fallen behind schedule." As a result, cost exceeded planned expenditures. *Id.* at 8.

1158. At this point in time they did not recalculate the savings. "Point-forward economics have not been calculated. Project benefits (savings) are delayed, but otherwise relatively unchanged from previous reports. They expect the "point-forward" economics "exceed those of previous requests and are very favorable." *Id.* at 11. Other "viable project alternatives (e.g. cancel, modify) have not been defined or evaluated. *Id.* at 12. "Restated economics would not contribute to the go-forward economic decision (e.g. complete, cancel, or modify). The inertia case has not been updated." *Id.*

Email October 23, 2006

1159. A month later, the amount of work completed on PS 1 is questioned. The most recent report stated that it was 71.3 % complete. However, on a walk through, the conclusion reached was that it was "somewhere between 20-30% complete. Ex. SOA-367.

Email from M. Thomas - November 5, 2006.

1160. In this email M. Thomas recommends a number of things. Number one, he recommends delaying another AFE supplement until after the startup of PS9.[551] Ex. SOA-3. This is to get a better grasp on the estimates and to get more time to prepare a less "optimistic" and better quality estimate with necessary documents in place. Number two, M. Thomas recommends: "Declare the breakdown – By IPA's criteria this project would be classed as a train wreck from a cost & schedule performance perspective. Projects in this situation can benefit by openly acknowledging the breakdown; stop; regroup; restart, thus re-energizing the team (including the contractors) around refreshed and achievable goals." *Id.* Number three, is to revisit project priorities in other words, to "switch project emphasis from cost/cash flow management to operational readiness, secure start-up, and contingency planning, especially for potential post commissioning

[551] At the time they were working on an estimate by mid-December and start up in parallel. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

problems." Number four, is to add resources, to enable all the baseline systems and documents to be brought up to date, and for the assurance process to happen. "Get some "fresh eyes" in to look at it all." *Id.* Finally, number five, is the level of funding, it is unlikely that the risks will be adequately compensated in the final estimate, because "several are unknown unknowns." *Id.*

PS 4 & 9 Contractor Variance Analysis-Larkspur

1161. In a December 5, 2006, letter Larkspur conducts a variance analysis of PSs 4 and 9. The letter states that the June 2005 contractor estimates were based on "reduced scope of work with non IFC drawings, incomplete cable schedules and unknown security requirements. In addition, late engineering, equipment deliveries, incomplete module fabrication and funding impacts were major contributors to the construction cost growth." Ex. SOA-195.

Email December 18, 2006

1162. A summary of an SR risk assessment workshop describes the base case as two contractors continuously working at 2 pump stations at a time, PS 3 startup in July 2007, PS 4 startup in early 2008 and PS 1 startup in 3rd Q 2008. Ex. SOA-327 (email from J. Ray). Concerning the base case costs J. Ray states "I personally struggled with much of the logic and do not put a lot of faith in the estimates created in the workshop."[552]

1163. The lead case now is "going to a sequential approach, i.e. one pump station at a time." This is supported by the Owners and Alyeska. In addition, the observations point out that one pump station at a time approach may allow for a competitive lump sum bid for the remaining work at PS 4 and PS 3. No scope creep should be reemphasized and the only changes should be for safety or code requirements "and these should be approved at the highest level." *Id.*

December 2006 Risk Assessment

1164. "The extreme project overruns prompted the owners to intervene in December of 2006 with a full scale review of project progress and cost. A risk assessment was completed and it became apparent that the current project plan could not be implemented," there would be cost overruns, "and that a valid execution plan had not been developed for Pump Stations 1 and 4." Ex. SOA-279 at 5. This resulted in discontinuing work at all PSs except 9 where work was nearing completion. The decision was made to move forward with a funding and schedule strategy that included completing PS 9 in early 2007, PS 3 by the end of 2007, PS 4 by first quarter 2009 and

[552] The costs the workshop produced showed an increase in capital from $454 estimated in September to $502 with a projected increase from $137-144M up to $175M. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

PS 1 by first quarter 2010. *Id.* "Alyeska was also directed to fund each pump station with discrete AFEs allowing better control of capital authorization. *Id.* An audit of AFE S020 expenditures was also conducted in late 2006 which revealed (1) "a lack of traceable audit trail, including difficulty substantiating charges against invoices." Number 2, "a lack of supporting documentation for coding charges to the S020 AFE and for charge reclassifications from capital to expense." Number 3, "inadequate use of units of property where capital purchases were not adequately linked to a fixed asset register, nor to a particular location." *Id.*

1165. "During the risk assessment process, Alyeska also came to the realization that authorized funding would be exhausted in January, 2007 instead of March, 2007, as had been communicated to the Owner Companies."

Discussion 2006

1166. SR Project Consultant Pete Flones stated that preliminary engineering should have taken 2-3 years. Ex. SOA-171 at 1-2. *See* discussion above, concerning Sanders testimony.

1167. The Reconfiguration Variance Analysis found that in some areas, the scope increased by as much as a factor of three. Ex. SOA-213 at 2.

1168. The Carriers recognized that there were an "unusual amount of field engineering corrections, which has impacted both cost and schedule. Ex. SOA-63 at 2.

1169. Anadarko is correct that the Carriers knew and ignored that the project had become a "train wreck." Instead the Carriers continued on without adequate review. They sought to justify their continued spending with point-forward economics arguing that the money already spent was sunk. Anadarko argues that the Carriers knew they should have properly scoped the project and if at any time the Carriers would have done their point-forward economics correctly, they would have seen negative results and the project would have been stopped. Anadarko argues that part of the Carriers were serving an agenda dictated by affiliated masters. BP was the primary driver for SR. It had significant motivation since its production affiliate had booked 63 million barrels of proven reserves. Ex. AT-1 at 26-32, AT-214 at 24-25, SOA-353 at 8, SOA-11, SOA-386, and AT-15. The other Carriers did not know this.

1170. In April 2006, an analysis of cost over runs states that one of the reasons for the cost overruns was the failure "to establish a clear work breakdown structure early in project" and that they were "[r]unning blind' without [it] early in project." Ex. SOA-340 at 18. This same BP project review concluded that a "fully loaded schedule not available in an adequate form until after construction began (FEL was rushed)." Ex. SOA-340 at 5. Additionally, it found that the baselines were always changing and that there was not a good summary of overall program progress until November 2005. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1171. A status update dated April 2006, states that a fully resource loaded integrated schedule is being prepared and expected to be complete by May 15, 2007. Ex. SOA-342.

1172. The funding request for retained buildings for PS 5 stated:

> The SR engineering firm assumed that because these buildings did not contain processes that would remain after SR nothing within the building would remain operating, therefore the building would not require power and any fire systems could be removed. During detailed engineering it was observed by the design engineering firm that the controls for some process equipment were located in buildings slated to be taken out of service. SR discussed this issue with the Fire Marshal when investigating how this would affect the plan to remove the fire systems. The Fire Marshall indicated that the fire systems would be required unless the building was truly being removed from operation and therefore not being provided with power. This is part due to the foam insulated metal clad panel issue described above. This resulted in retention of several buildings slated to be taken out of service, and retention of their fire systems as well.

Ex. SOA-150 at 11.

1173. Howitt testified that there were additional costs at PSs 1 and 4 because Alyeska could not meet the December 31, 2008, deadline agreed to with the Fire Marshall and had to upgrade the fire protection systems. Tr. 4362:1-10.

1174. In March 2006, the Carriers realized that concurrent startup did not allow them to learn from one pump station to the next. Ex. SOA-229. Thus, the Carriers revised their plan. Ex. SOA-230. However, note that this had been the recommendation of Bailey, to do a prototype or pilot project at one of the stations. Hisey testified that it was imprudent to attempt to implement the SR Project at all the pump stations at once rather than one at a time. Tr. 3839:10-3940:12. According to Hisey a phased approach allows a crew to learn from their first pump station, and to use their learned skills on subsequent pump stations to perform the work in a better, faster, cheaper manner. Tr. 3839:14-3840:12. Carriers' witness Crider also agreed with this concept. Ex. ATC-34 at 11:17-20; 15:18-16:2; Tr. 5171:13-5175:19.

1175. The design of the control systems upgrades was not fully developed. In December 2004, Hinz issued its design of the changes to be made to the F370 SCADA system as part of SR. Ex. AT-517 at 3. The original design was revised numerous times during 2004-06. Ex. AT-517 at 3. Hinz stated that it was designing "the detailed implementation of additions to the Supervisory Control and Data Acquisition system originally installed as part of the F370 project. Ex. AT-517 at 6. In 2006 the project was not completed. In April 2006, Hinz was relieved of its responsibility for "design testing and development" of software for the control systems and the responsibility was given to Alyeska. Ex. AT-511 at 3. Hinz stayed on to provide support. At the time, Hinz

20140227-3052 FERC PDF (Unofficial) 02/27/2014

reported there were unresolved engineering issues and concerns regarding design. Ex. AT-511 at 7. It noted that "[m]ost inquiries coming from the field show a lack of: project communication, project material standards, and general construction practices and methods." Ex. AT-511 at 9. At this point in time, the important elements of the SCADA system were incomplete, poorly structured, and inadequate for service as delivered. Ex. At-433 at 59; Ex. AT-414.

1176. Conoco notes that "Project Management Systems inadequately staffed" and that the "significantly strengthened organization still did not have the experience sets to deliver the project." Ex. SOA-428 at 8. This contradicts the Carriers' arguments that the PMT was staffed with qualified individuals. The Carriers claim that the problems faced by the PMT after 2005 were "primarily the result of the industry-wide labor shortages. Carriers IB 175-75. However, as the State correctly points out the evidence in this case shows that mismanagement was the primary cause of the projects problems. Costs could not be controlled ($31 million increase total projected costs $418 million (Ex. SOA-207); there were extreme project overruns in December 2006 which required "an attempt to restructure the funding and schedule strategies" (Ex. SOA-349); the project schedule was still not resource loaded in May 2007 (Ex. SOA-342).

Conclusions 2006

1177. At this point in time, the Carriers are still working on freezing scope. This is now the second year of construction and they still have not frozen scope. They do not have an automation design completed, they do not even have a full plan ready yet. The Carriers still have the same incompetent contractors Hinz and SNC and they still are not managing them appropriately. Costs are still escalating. This is what they knew. The cost estimates for Supplement 2 were wrong because detail design was not finished. The Owners knew the schedule was tight, as a result, they should have known that they needed more time to do a thorough job, and they should have known that the rush to completion was at the expense of other things such as quality. They knew they approved the project before detail design was complete. The consequences of this are the cost overruns. This is in they should have known category. The more analyzes of the evidence in this case, the more troubling issues arise. For instance, in April 11, 2006 there is an admission that PS1 had marginal economics. One may ask why did the Owners agree to electrify PS1 if it had marginal economics? Additionally, it is not credible that PS1 will have the least impact on project economics as it was "the most marginal … in the investment scope," (Ex. SOA-370) since PS 1 had always been factored into project economics. Moreover, the document also cannot pinpoint how much of the alleged savings from the project were attributable to PS1. Ex. SOA-370.

1178. It is not credible that the new schedule results in the early delivery of the benefits for the pump stations with the greatest cost savings for PS3 and 9. Ex. SOA-370. The delivery is now scheduled for the fourth quarter of 2006 and early 2007 nearly two years beyond the original schedule.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1179. It is not credible that economics would be the same when expenses and capital exceed previous estimates. They knew they had not recalculated the economics and as a result their analysis was flawed. Moreover, other alternatives such as modifying the project or canceling had not been studied either. In November 2006, BP personnel recommended declaring a breakdown or that the project was a train wreck from a cost and schedule perspective. However, "[r]estated economics would not contribute to the go-forward economic decision (e.g. complete cancel or modify)". Ex. SOA-63 at 12.

1180. From October 2006 to December 2006 they changed the startup date of the pump stations.

1181. At this time, the Carriers are still evaluating the reliability of the new equipment. In a white paper presented to the Owners Committee it was reported that the MTBF [mean time between failure] for the Siemens Cyclone TGs was assumed to be 12.8 years. The Cyclone user's group stated that this was grossly optimistic. Ex. AT-418 at 3.

1182. There is no evidence in the record that PMT staff were ever embedded with the SR projects' primary contractors.

9. What happened in 2007

January 12, 2007

1183. In an email, J. DeHaas in essence states that the primary advantage of the Siemens over the Avons was efficiency. "However, due to the concept implemented by SR we loose most of the efficiency we gain, in the generator, transformer, VFD and EM motor." He follows this by stating, "[o]n a fired cost per Hp hour, exclusive fuel costs, the new Siemens may be as expensive or more expensive to operate than the Avon. . . The life expectancy will probably be similar, with the cost of a complete Siemens overhaul being more than a comparative Avon overhaul." Ex. SOA-22. The only advantage of SR as he "sees it is the remote operation concept, which will eliminate some manpower." "The manpower it will eliminate is fairly expensive as well. On the maintenance end of this it should be some savings. *Id.* He is still skeptical that the economics will work out since "per most of my experience projects like these usually only have positive economics if the fuel (energy) costs are a real factor." *Id.*

January 23, 2007 SR AFE Audit – Scope Inputs

1184. In an audit certain Owner alternates revealed that the Conoco representative is concerned with baseline costs and non SR AFE costs creeping into SR AFEs and *vice versa.* In addition, there is concern about whether the costs charged AFE S020 are consistent with the approved scope. Ex. SOA-329. The Owner alternate for BP is also concerned with how costs are being tracked *vis a vis* AFE S020 and that scope changes are not being well managed. "Owners thought they had put a lid on out of scope changes

20140227-3052 FERC PDF (Unofficial) 02/27/2014

but concern is additional work creeps in." *Id.* The representative for Exxon noted the lack of scope definition early on but for the past 18 months the SR Team has implemented changes without approval before the fact. *Id.* at 2. He feels that "MOC re: scope changes was weak." He is also concerned about the fact that the crews at PS 3 and 4 are too large after the decision to scope back and he does not know what they are working on and whether coding was appropriate. *Id.* He notes that the scope of security has changed significantly. *Id.* Additionally, he is concerned that Program staff has grown to approximately $6M per year.

SR AFE Audit-Meeting with Lee Monthei-January 29, 2007

1185. Lee Monthei provided his perspective of the contributing causes of SR's significant overruns. Ex. SOA-308. He stated that the original estimate of $250 million was based on conceptual engineering. As a result, "a fundamental flaw was believing this estimate was valid, without the benefit of preliminary and final engineering." Along these lines he adds that there was intense pressure from the Owners to get the project sanctioned, to get tax advantages if completed by December 31, 2005. *Id.* Consequently, the "project failed to follow the typical stages of conceptual, preliminary and final design engineering and then implementation." He relates that even though the Owners had been told that design engineering was not complete they decided to proceed to implementation. This ""fast tracking" (implementation prior to final design) caused significant risk." *Id.* Moreover, he asserts all those involved in the project failed to realize how complex the project was. Additionally, cost estimating by SNC was deficient. He also asserts that Lakspur (engineering firm retained to validate the estimates) was pulled off the engagement prior to their completion because their estimates were too high. *Id.* The project team did not really understand that engineering was only 60% complete instead of 90% as represented by SNC. *Id.* Further, the cost control system was not robust and cost control staff did not have the necessary skills.

1186. The decision to not stop the project was also based on the erroneous belief that engineering was more complete than it actually was. *Id.* at 1-2. In addition, he asserts that the design given to the fabricators was bad and incomplete. "There were approximately 12,800 revised drawings which is unacceptable." *Id.* at 2. "To meet construction windows in the field, fabrication work was not completed prior to leaving the fabricator and, therefore, had to be completed in the field which is always more expensive. SR modules were not "self-sufficient" in that extensive tie in work needed to be performed in the field, which Lee felt was different than typical module work on the Slope. The amount of wiring and cabling was much more than anticipated. *Id.*

1187. Monthei also challenges the decision to start implementation prior to receiving NTP's from the JPO stating that this contributed to inefficiencies estimated in the millions. "Subsequent re-work tied up critical engineering resources." In addition he points out "that "cultural" differences between US and Canadian engineering definitions of "deliverables" caused inefficiencies (e.g. the absence of a load study)." *Id.* Further, he asserts that Canadian engineers allow for more engineering to be completed in the field.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Id. In terms of staffing he points out that the SR Management Team was understaffed due to the erroneous belief that this was not a complex project. Staffing costs were larger than expected due to supply and demand. *Id.* He asserts that the Project did not have a good plan for dealing with JPO and ECP concerns given the size of the project. *Id.* Additionally, he states that the "lack of availability of skilled craft also added costs." Monthei felt that other Slope work together with demand in lower 48 (e.g. Hurricane Katrina) caused shortages of craft. In addition to shortages, there was also a high turnover of skilled craft with VECO and PPC." Ex. 308 at 2.

February 2007

1188. By February 2007, the SR project exceeded approved funds. Ex. SOA-380 (email from K. Hostler, February 1, 2007). They are still having issues with project control capability and are considering hiring a new company to provide project management and control systems and staff. *Id.* Discussions have included outsourcing all projects to this new company. There are concerns about this proposal (creating a "projects" organization separate from Operations and Maintenance). "We did that when we set up the Owner Project Team responsible for the SR Project itself. That did not work out too well primarily because the Project Team chose to ignore Alyeska's established Quality Control and Assurance and Project Processes. Clearly our employees and the regulators would not be aligned with an 'outsourcing' approach." *Id.*

1189. Interim funding for SO20 was approved in February 2007, to cover shut down, forward planning, and caretaker costs at Pump Stations 1, 3, and 4 for the first quarter of 2007. Ex. SOA-279 at 6.

1190. In an email dated February 9, 2007, J. Martin states that alarm flooding will become a problem since they have rewritten the alarm descriptors and unthreaded the common critical alarms. Ex. AT-523. This email points out that by "definition, the current condition of the UCOS alarms and alarm management system does not meet the minimum requirements for a rational person, using the SCADA system, to accept responsibility for the safe operation of the Pump Station facilities." *Id.* Further, Martin (an OCC controller) stated that "training has failed to recognize the impact of introducing into SCADA, what is in effect, an entirely new Pump Station replete with many complex new systems and interdependencies." *Id.* at 2.

1191. PS 9 was started up on February 20, 2007. According to this document, savings are obtained from increased pump efficiency and fuel savings. Ex. SOA-279 at 6.

Cost Engineer Warrior Princess February 28, 2007

1192. On February 28, 2007, D. Ownes ("Cost Engineer Warrior Princess") writes an email looking for the Larkspur estimates. Ex. SOA-255. D. Ahrens responds acknowledging a Larkspur study in December 2003. He states that he remembers Larkspur finding the estimates light. Additionally, he states that he responded by

20140227-3052 FERC PDF (Unofficial) 02/27/2014

requesting additional contingency which was subsequently removed as the Owners "reduced our contingency and overrun limitation on the sanction AFE request. He also states the $200M is complete crap and we didn't keep anything secret. We shared the Larkspur report with the Owners." *Id.*

March 2007

1193. In March 2007, Alyeska hired a large project manager and engaged Worley Parsons as a project controls team, to assist in the creation of the Supplement 3 funding package and to complete project controls work at PS 3 during construction, functional check-out and start-up. Ex. SOA-279 at 6.

1194. An undated document Ex. SOA-257 lists a number of items.[553] It starts out by listing the changing industry environment included a tight labor market. The document states that the fast track schedule was "to take advantage of one time tax savings of about $100MM." According to this document "not enough time was spent in the early design phases of the project" and ""fast tracking" the project allowed design to start before the conceptual engineering and preliminary engineering was complete. This resulted in a large amount of changes as design scope was finalized. Construction in the field started before design and material procurement was complete. As these activities were delayed, impacts to construction crews resulted. Several re-estimates on construction costs were needed as a result of changing designs and work scope. (12, 800 drawings were issued after September 2005)." *Id.*

1195. Additionally, the document points out that there was a failure to recognize the project as a "Large complex project (LCP) and this resulted in inadequate planning due to over simplifications or understanding impacts and risks." "Project cost contingencies were inadequate for a LCP. Executing plan was not realistic for a LCP. Not enough Project staffing was provided for a LCP." It goes on to point out that the change from SNC to Alyeska caused major disruption to the project. Further, SNC's inability to perform impacted the project schedule and costs, a concern with the JPO and late delivery of engineering design caused significant delays and impacts. *Id.* In addition, the document states that SNC was not able to perform project control functions on SR and Alyeska did not have sufficient staff to perform all the project control functions after transitioning to Alyeska.

1196. Concerning engineering design, the document points out that the quality of the design documents was poor and required significant field changes. "The state of design completion was overstated on many occasions and this resulted in field work starting prematurely." *Id.* at 2. "There were many problems with design of the control systems that required Alyeska to intervene and bring in new resources to complete the engineering." *Id.* It points out that Alyeska was not prepared for the changing market

[553] The Joint Chronology dates this document to March 6, 2007. Ex. J-2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

conditions that increased demand for engineers and workers. *Id.* The "[o]riginal Project AFE cost estimate was erroneous." "Conceptual engineering estimates were used for the first AFE estimate." "Many assumptions were incorrect." "There were many scope changes that affected project costs." Further, it points out concerning the cost estimates, that the "Owners removed contingency and other scope items that had to be added back later on." *Id.* Because work started prior to getting JPO NTPs, JPO required changes necessitated construction re-work and additional costs. Finally, "[s]chedule delays added significant costs to the project." *Id.*

1197. In a March 20, 2007, email K. Eldridge notes the problems with the alarm systems. For instance, he states that "we were unable to determine the depth of the inept alarm management design implemented in the SR software until shortly before PS09 SR pumps were to go live." He mentions code issues, alarm flooding and improper prioritization of the alarms coming into the OCC, the number of screens that can be open at UCOS platform at one time. Eldridge also asserts that the HMI Work Group had a limited mandated "to write a standard for the department and fix navigation problems within the operating limits of the "off the shelf" software product." Yet they were "shanghaied into being a labor pool for the SR group to do SIPPS, Transition Screens, PS09 start up and alarm description rewrites." He conveys that it was difficult to get anything done because of the time constraints due to the project schedule, "lack of cooperation and the sheer volume of the problems we uncovered that needed to be fixed or designed and added." Additionally, he mentions, that the HMI Work Group cannot accept "accountability" to fix problems with the system that should have been resolved at the project level long before it was put into production. "It is illogical to assign accountability to an individual if you don't also assign them the resources and authority to accomplish it. I will not stand by again and watch my coworkers or myself be subject to the level of resentment, disrespect, intimidation and belligerence shown towards us when we were the HMI Work Group." Ex. AT-406.

1198. In a March 25, 2007, email J. Martin states that the HMI Work Group worked to rectify as many of the HMI deficiencies as possible prior to delivery to operations. He adds that unfortunately, "due to time and resource constraints only 20% of the necessary corrections were completed. These were only the most critical HMI deficiencies. Much more work remains to be done, many of these still needed corrections are closely associated to alarm management problems." Ex. AT-515. This is close in time to the start-up of PS09. Martin also states that the "problems with the alarm management scheme are so broad and far reaching that there is no possible quick fix. The process is fatally flawed at its foundation and all of the subsequent structural decisions are flawed as a result. Unfortunately, we were not able to make a difference in this outcome because we were not involved early enough in the process." *Id.*

1199. In a Progress Report dated March 31, 2007, the HMI Work Group states that the number of alarms in the future with full S/R implementation is 35,000. The document states this is an "increase of 24,800 alarms that will be directed to the OCC Controllers

20140227-3052 FERC PDF (Unofficial) 02/27/2014

attention at some prioritization level. This represents a 269% increase in alarm volume over the F370 Project volume. Virtually all of these new alarm points are generated by new equipment and systems unfamiliar to the existing OCC Controller staff. It asserts that it is "evident that this dramatically increased level of complexity must be reduced to a manageable level or positive control of the system will not be possible." Ex. AT-532 at 2. The document states that the "alarm system is not fit for purpose and is now placing the OCC and the entire TAPS system at a higher level of risk and if not corrected now, the level of risk will continue to increase with every additional S/R facility alarm stream brought on line." *Id.* The root cause of the problem according to this document is the result of the decision "to defer this fundamental, project work element to a later time in the project." *Id.* As the document states in "the normal course of a project of this type, you would expect that a top down alarm management philosophy and rationalization filtering template would have been developed before the process of assigning alarm priorities and groupings could begin." Ex. AT-532 at 2.

April 2007

1200. In April 2007, additional interim funding was approved to return contractors to the field at PS 3 to ensure schedule delivery for start- up at the end of 2007. Ex. SOA-279 at 6.

1201. In a Risk Assessment dated April 20, 2007, it is pointed out that a comparison "of the alarm management system as delivered by the S/R Project" to the "generally accepted industry standards" (Electrical Equipment and Material Users Association, EEMUA Publication 191) "is distressing." Ex. AT-516 at 4. It points out that the "alarm management scheme as delivered to OCC does not reflect the fundamentals of this body of knowledge." *Id.*

1202. AFE S920 requests $6.36 million ($5.63 capital and $0.73 expense) to complete electrification at PS9. Ex. ATC-378. This document identifies new scope items including installation of load band and controls to synchronize the 2.25m generators. *Id.* at 3. The document also points out that economics have not been calculated for the AFE since the activities are components of the original economics of S020.

May 2007

Project Control Assessment and Corrective Actions-Discussion ` Outline- May 4, 2007

1203. This May 4, 2007, assessment states that incomplete scope definition is one of the causes of "forecast surprise". Ex. SOA-208.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

AFE S320 Completion of Pump Station 3 Electrification and Automation

1204. At this point in time, Alyeska has been directed by the Owners to seek additional funding in new AFEs that are specific to each pump station. Ex. SOA-121 at 2 (Ex. ATC-379 is a similar exhibit), *see* also Ex. ATC-404. AFE S320 is a request for $39.3 million ($30.4 million capital, $8.9 million expense) to complete the construction, commissioning and start-up of Pump Station 3.[554]

1205. It is anticipated that new "AFEs will be prepared to provide completion funding for other Pump Station 3 work, including related Lifecycle (AFE F736 $3.945 million), Retained Buildings Fire & Gas (AFE F731 $20 thousand),[555] SIPPS (AFE F738 $35 thousand),[556] Security and Site Grading activities (AFE F734 and AFE F735, $3.865 million)." *Id.*

1206. Now it is anticipated that the work will be completed in 2007 but the operational acceptance period will carry over into the first quarter of 2008. Pump station 4 "activities are planned for 2008 with Start-Up in 1Q 2009, and Pump Station 1 activities are planned for 2009 with Start-Up in 1Q 2010, subject to economic justification." *Id.*

1207. The reasons stated in the AFE for the additional funding is "primarily because engineering progress was overestimated in the previous request, resulting in an understated forecast of total cost.[557] Completion of engineering design in 2006 resulted in identification of additional work, and the additional work resulted in extended project duration. *Id.* Some design elements were delivered late, slowing fabrication and construction. *Id.* at 10. This also resulted in revisions to the execution strategy. For

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[554] The projected cost to complete SR is now $569.9 million. Ex. SOA-121 at 9. Note that this figure is not congruent with the December 2006, project spent $578,605,500. Ex. SOA-387 at 4.

[555] This AFE was previously AFE SO41. *Id.* at 7.

[556] AFE F738 was previously AFE S038 SIPPS. *Id.* at 6.

[557] "The previous supplement was based on contractor estimates that assumed engineering was 90% complete (excluding field engineering and software automation)." *Id.* at 9. However, the engineering progress was less, estimated in the range of 50-70%. *Id.* "Based on the reported engineering status, construction mobilization occurred sooner than it would have if actual engineering progress had been known, resulting in reduced construction productivity and slower progress than planned. Equipment and materials identified during design completion also led to late procurement, which caused other construction delays." *Id.* It also states that by drawing count, over 100% of the project's drawings have been issued or revised since the previous funding request. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

instance, they transferred module completion to the field, which added costs and additional work to the field schedules. "The FCO work that was planned to occur in the fabrication shops could not be completed there, which compounded the impact of the delays." *Id.* at 10. Further, field engineering corrections and clarification have been required to resolve a larger number of issues than anticipated. This resulted in higher costs and delays. Staffing shortages and shortages of skilled craft labor and materials also contributed to the delays. JPO approval and requirements also caused delays. *Id.* at 10.

1208. The AFE states that pump station 3 construction is approximately 75% complete. *Id.* at 5. Approximately, 30% of Functional Checkout (FCO) has been completed. *Id.* at 6. Concerning cost savings the AFE states that completion of the project has higher value than deferral of the project. *Id.* at 8. Additionally, related to risk it states that the identified alternatives carry greater cost and scope uncertainty. *Id.* There is no evidence on the AFE to justify these statements.

1209. It also states that following the Risk Workshop in December 2006, the project execution strategy was changed to implement one station per year over the next three years. *Id.* at 10. Related to automation and software development, the AFE states, that at the time of the supplemental AFE programming for control systems was a strong concern. *Id.* "Coordination between the engineering vendors was inadequate and the engineering effort had fallen behind schedule. However, a successful recovery effort was implemented in terms of schedule and quality; nonetheless, recovery costs exceeded planned expenditures." *Id.* at 10. Staffing levels have grown in part to manage the increased request for information from regulators and to resolve concerns. *Id.* at 11. The document on page 14 shows the scope changes for PS 3 including changes that were not anticipated and those not adequately defined or funded due to insufficient design completion or inadequacies. *Id.* at 14. Such as SCADA and module resizing.

1210. The alternatives considered are described in this document. *Id.* at 15. They were rapid implementation, deferral for seven years,[558] cancellation[559] and phased implementation, the recommended alternative. *Id.* at 15-20. Completion activities will occur sequentially one pump station at a time. Pump station 3 will start in the 4Q 2007. Pump station 4 completion will be funded after "demonstration of Pump Station 3 power generation effectiveness, with construction in 2008 and planned Start-Up in 1Q 2009; and Pump Station 1 will be implemented in 2009 for 1Q 2010 Start –Up, providing the remaining work at Pump Station 1 is economically justifiable." *Id.* at 19. The document points out that the revised LRP includes additional funding for existing turbine maintenance in anticipation of longer service. *Id.* The "Phased Implementation alternative offers the greatest economic value and lowest operational risk of the

[558] Note that the estimates are rough-order-of- magnitude. *Id.* at 33.

[559] No economic evaluation of this alternative was conducted. *Id.* at 18.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

alternatives that have been evaluated. In addition, this alternative offers the greatest cost certainty. *Id.* at 20. This alternative has a $133 million higher NPV than the Deferral alternative. *Id.*

1211. The document points out that PS 9 is operational but the control system is in the run-in phase and not yet accepted by operations. *Id.* at 21. The estimated total S020 Comparable Funding at Completion is $660.6 million (not including hyper-inflation). *Id.* at 30. The total PS 1, 3, 4 and 8 funding at completion is $718.1 million. *Id.* at 31.

June 6, 2007

1212. The record contains a slide show titled SR-AFE S020 Supplement 3 by Conoco dated June 6, 2007. EX. SOA-388. It states that construction began at all four pump stations simultaneously in the first quarter of 2004. Further, it states, that funding supplement 1 was for power generation scope changes. Supplement 2, was for regulatory driven changes, incomplete engineering, inaccurate estimates, inefficient project execution and inadequate project controls. *Id.* at 3. The document notes that PS 9 start-up occurred in February 20, 2007. This document states that supplement 3 is for PS 9, 3, and caretaker for PS 1 and 4 for a total of $122.89 MM. The work to be done for PS 9 post start-up, is back-up power (black start generator), permanent Artic load bank, therminol system replacement. *Id.* at 4. For PS 3 (there was an interim funding approved by the other owners but not Conoco) the work scope is to complete construction and functional check-out, commissioning and start-up. *Id.* Pump stations 1 and 4 caretaker work scope is described as demobilization and caretaker activities for PS 1 and 4 in 2007 and PS 1 in 2008. *Id.*

1213. Further, the document states that a risk assessment completed in December 2006 had recommendations which were implemented. This were: change the project management team; Alyeska employed third party project controls team, shut down all work other than at PS9, future work to be handled on a Pump station by pump station basis, each pump station will be justified separately and managed as a separate project. *Id.* at 11. Additionally, it states that a financial audit was completed in the first quarter of 2007. The main findings of the financial audit are listed as: lack of audit trail, lack of supporting documentation for charge reclassifications, inadequate use of units of property. *Id.* On page 12 it describes how the original AFE S020 assumed start-up of all PS by the fourth quarter of 2005. Supplement 2 assumed start-up of all PS by first quarter of 2006. Now the schedule shows PS 9 finishing by 4th quarter of 2007, PS 3 by second quarter of 2008, PS 4 by first quarter of 2009 and PS 1 finishing by second quarter of 2010. *Id.* at 12. The document proposes several funding options and recommends funding PS 3 with Supplement 3; the remaining work would be funded with a fourth supplement. *Id.* at 13. Funding to be allocated to Alyeska on a "Pay as you Go" and pump station by pump station basis.[560] *Id.* The document includes a risk mitigation

[560] *See also* page 15.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

and execution strategy which would have among others, owner attendance at weekly construction meetings by phone, owner mirrored project controls and close review of key performance indicators. *Id.* at 20.

June 19, 2007- Why did we get off track

1214. Another presentation (slide show) from Conoco is dated June 19, 2007. Ex. SOA-209. The document points out that PS 9 start-up was on February 20, 2007. *Id.* at 3. The explanation as to why did we get off track is as follows: incomplete engineering (only 60% complete vs. 90% reported), delays, rework, work location shift to field, inadequate project management and project controls, the new team at supplement 2 did not have large project experience, turbine corrosion, resource constraints, scope changes. *Id.* at 9. The exhibit states that Alyeska does not have the capacity to provide AFE quality deliverables for PS 1 and 4 at this time, their cost estimates are questionable, the "ROM estimates for PS 1 and 4 have uncertain scope and extremely high levels of contingency (> 60%)", the project scope at PS 1 is likely to change (decrease). *Id.* at 11. They now have a new project manager. *Id.* at 15.

June 21, 2007 - Supplement 3 – Conoco

1215. This document describes the third supplement to AFE S020 as a request of funds to complete the electrification and automation work scope at PS 9 and 3 plus caretaker funding for PS 1 and 4. Ex. SOA-279. Additionally, it points out that a request to fund the project to completion at PS 1 and 4 is not being made due to the fact that "AFE quality documentation is not available, current completion status at these Pump Stations has not been determined, and the full scope of remaining work may not be justified.[561] *Id.* at 3.

1216. This document points out that the project was sanctioned following completion of preliminary engineering with approximately 15% of detailed engineering complete. Again the document points out costs have increased, and schedule delayed, due to "expedited schedule drivers, incorrect regulatory commitment assumptions, inadequate project management processes, uncontrolled scope changes and delayed operations input to the project execution plans." *Id.* at 4. "Regulatory and operational requirements identified during conceptual/preliminary engineering were incorrect, most notable of which were those associated with the Brownfield Facilities and interconnect requirements to the Greenfield Facilities." *Id.* Established project management and control processes were not utilized" and those "that were utilized by the second project management team proved ineffective." *Id.* Additionally, "[s]cope changes were not subjected to a rigorous management of change process and the magnitude of the scope changes were not recognized in time to add necessary resources to assure the contractor's ability to deliver

[561] The project scope at PS 1 is anticipated to decrease due to the potential use of the Prudhoe Bay power grid for primary power. *Id*. at 8.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

as agreed." *Id.* Project delays were also caused by the failure of critical equipment to pass initial vibration testing criteria. *Id.* In mid - 2006, within a month of authorizing interim funding, the Owners were notified of upward pressure on the project due to incomplete work list items, unreported contractor change notices, and a change in project schedule. *Id.* at 5.

1217. The cost and schedule variances are attributed to overstated engineering design, inadequate project management and controls processes, engineering delays and rework, late regulatory approvals, turbine generator issues, low labor productivity and high inflation rates. *Id.* at 10. Further, it states that "over 100% of the project's drawings have been issued or revised since the previous funding request. *Id.* Moreover, the document points out that since the last supplement the project controls staff was not enhanced to compensate for the project control shortfalls identified. The project control tools consisted of unmanageable Excel spreadsheets instead of a specialized, industry proven cost and schedule tracking system. *Id.* Additionally, field engineering corrections and clarifications required to resolve a larger number of issues than were anticipated. *Id.* This impacted both cost and duration. *Id.*

1218. The economics of the project are described as positive due in large part to the sunk project costs and negative consequences of the cancellation/delay alternatives. *Id.* at 13. "The current full cycle economics have decreased considerably with an AARR of 11% and NPV of -$14.6 million (PI 0.8, 12 years breakeven)." *Id.*

1219. Supplement 3 funding was recommended for the following reasons:

- The original execution plan is not feasible with an Alyeska Project Management Team; they have neither the resources nor the experience to maintain adequate oversight at three major construction sites simultaneously.

- The amount of construction remaining at Pump Stations 1 and 4 is very uncertain. A great deal of work remains to have a robust project execution plan and AFE quality estimate for the remaining scope of work at these two locations.

- Better estimates are required for work at PS1 and PS 4, as well as a better understanding of the Alaska tax structure and future tariff rates before a firm recommendation can be made on proceeding to completion at these locations.

Id. at 16-17.

July 11, 2007

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1220. An SR audit (#07-04) dated July 11, 2007, (for the period October 2002 to December 2006), concludes that the internal controls evaluated within the scope of the audit were unsatisfactory. Ex. SOA-387. There is no effective audit trail. There was no traceability between the project transactions in the General Ledger (G/L) and Project Accounting (P/A) systems and invoiced amounts. This creates uncertainty as to the validity of the data in the G/L and raises concerns regarding the reliability of financial data used for project management. *Id.* Other project control issues were also noted. To wit, accruals, the absence of integrated project work schedules, and barriers between Project Controls and the Accounting Department. *Id.* at 2. "In addition, the methodology used to allocate certain costs between SR AFEs and Renewal AFEs was not always supported and did not allow for the determination that costs matched the scopes of work described in the smaller Renewal AFEs. In certain cases, more than 75% of the total expenditures for the smaller Renewal AFEs were captured as a generic allocated cost." *Id.* Preliminary review of vendor invoices identified that invoiced amounts for SR work may not always be consistent with the terms and conditions of certain vendor contracts. *Id.*

1221. High risk Finding Number 1, project controls for SR AFEs were inadequate and do not assure management that SR costs are being properly captured and reported. There is no traceability between the G/L, the Project Accounting systems and the vendor invoice. *Id.*

1222. High risk Finding Number 2, the amounts allocated/re-classed from AFEs S020 and S026 to the smaller Renewal AFEs, were not always properly supported. The allocation method prevented the determination that costs matched the scopes of work described in the smaller Renewal AFEs, and did not provide sufficient information to determine the actual total costs of individual assets. *Id.* Additionally, the finding states that the "allocation methodologies erode the "audit trail" by creating the inability to observe how source transaction data flows through the accounting system, and hinder the capability to use actual costs for trending or forecasting purposes. *Id.*

1223. High risk Finding Number 3, the costing method for units of property was inadequately defined, developed, and implemented at the beginning of the project and did not fully consider the complexities of assigning costs to units of property in light of the project accounting processes. Thus, the costing of units of property is manual and labor intensive. *Id.* at 2-3.

1224. Low risk finding Number 5, certain SR AFE costs may not be captured as capital or expense costs consistent with FERC and GAAP requirements. *Id.* at 3.

1225. It is noted that as way of background the document states that SR is part of the vision to renew assets and the organization. *Id.* at 4. It goes on to describe how conceptual engineering was completed in 2002 and preliminary engineering further evaluated alternatives and verified project costs and savings. "The project was sanctioned in March of 2004 and detailed engineering began." *Id.* at 4. There is a list of

20140227-3052 FERC PDF (Unofficial) 02/27/2014

all the SR and Renewal AFEs approved as of December 31, 2006 (total $578,605,500). *Id.*

1226. The audit explains how in a previous 2005 review it was found that SNC personnel were not effectively controlling the project (#05-04). *Id.* at 5. Examples included late disclosure and elevation of project "red flags" and communication gaps between project controls and other users. *Id.* at 5. Consequently, the project controls function was moved from SNC to the SR Project Controls Team. Another review (#05-19) found that the use of non-system generated expansive spreadsheets to track expenditures and the lack of detail in the PA system precluded effective controls. The review also found there was no "look back" verification of prior accrual amounts to assess the reasonableness of the accrual process. In July 2006, the SR project controls function was aligned under the Alyeska Project Controls Manager and this was so at the time of the audit. *Id.*

December 31, 2007- AFE S420

1227. This AFE is for the completion of PS 4. The AFE requests $66.5 million ($60.6 million capital and $5.9 million expense). Ex. ATC-384. The document states that additional funding is required primarily because engineering progress was overestimated in the previous request, resulting in an understated forecast of total costs. The completion of engineering design in 2006 identified additional work and the additional work extended the project duration. *Id.* at 4.

Discussion 2007

1228. The Owners put pressure on the project team to get the project sanctioned. Ex. SOA-308 at 1. Although pertinent to the sanctioning analysis this evidence is corroborated in 2007 in an SR audit. This corroborates the finding that the Owners knew they had predetermined the outcome of electrification without sufficient engineering studies. L. Monthei stated that he understood Larkspur was "pulled off the engagement prior to their completion because the team felt that their estimates were too high." Ex. SOA-308.

1229. The original SR estimate of $250M was based on conceptual engineering. Ex. SOA-308 at 1.

1230. The Carriers feel they do not have control over scope growth over a year after the project was supposed to be completed. The Owners feel "Alyeska doesn't manage scope changes well. Owners thought they had put a lid on out of scopes but concern is additional work creeps in." Ex. SOA-329. Additionally, a review found that there were too "many change orders" and that the "root cause was starting prior to engineering being complete." Ex. ATC-376 at 12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1231. L. Monthei stated that the Project Team told the Owners the design engineering was not complete but was nevertheless instructed to proceed with implementation. All involved - Owners, Project Team- failed to realize how complex this project was. "Automation projects are typically complex and this fact was improperly discounted." Ex. SOA-308.

1232. In May 2007, Alyeska estimated that over 100 percent of the project's drawings were revised or issued since the previous funding request in 2005. Ex. SOA-121 at 9. Approximately 12,800 drawings were issued after September 2005. Ex. SOA-257. It is found that these were the direct result of the Carriers decision to sanction and accelerate the project before defining the scope of the project and completing engineering. Additionally, the design for the control system was also incomplete. These actions are not those of a reasonable manager and are thus found imprudent.

1233. The Carriers argue that Anadarko and the State disregard significant aspects of the record when the evidence conflicts with the narrative asserted in their witness' prepared testimony. They cite Adams testimony and exhibit SOA-121 stating that Adams focused on the statement in AFE S320 that "[b]y drawing count, over 100% of the project's drawings have been issued or revised since the previous funding request. Ex. SOA-121 at 9. The Carriers then state that this contention was specifically addressed by the Carriers witness Strub the SR construction Manager who helped develop AFE S320 (Ex. SOA-121). The Carriers cite Strub's testimony that the [protestants] did not differentiate between drawings that were newly issued and existing drawings that were revised. Straub's testimony continued "[s]ince this was a project that proceeded at sanction before completion of detailed engineering (which is not at all uncommon for large capital projects), there were several documents that were issued for the first time after sanction, exactly as would be expected." Strub then states that there are instances that a drawing is revised simply by changing a tag number. "This was the "revision" for many of the drawings alluded to by [the protestants], and these changes were not substantive." Carriers RB 46.

1234. First, Strub's assertion that it is not uncommon for large capital projects to proceed at sanction before completion of detailed engineering is an uncorroborated statement and not given significant weight. Moreover, this statement is contrary to record evidence. *See* AT-273. Second, the drawing revisions being non-substantive just tag changes is also unsupported and contrary to the record evidence. The cited exhibit itself contradicts Straub's testimony. For instance, AFE S320 states in the section "Capital Cost Increases" "Engineering Status Overstated": "[t]he previous supplement was based on contractor estimates that assumed engineering was 90% complete (excluding field engineering and software automation). It has subsequently been demonstrated that engineering progress was less than reported, variously estimated in the range of 50-70%. Completion of the remaining engineering resulted in identification of additional work, which was not included in the construction estimate, and the additional work resulted in extended project duration. By drawing count, over 100% of the project's drawings have

20140227-3052 FERC PDF (Unofficial) 02/27/2014

been issued or revised since the previous funding request." Ex. SOA-121 at 9. The document points out that "[b]ased on the reported engineering status, construction mobilization occurred sooner than it would have if actual engineering progress had been known, resulting in reduced construction productivity and slower progress than planned. Equipment and material identified during design completion also led to late procurement, which caused other construction delays." *Id.*

1235. In terms of engineering delays the document states: "[s]ome design elements were delivered later than planned which impeded fabrication and construction activities. The execution strategy was revised to mitigate the impacts of these delays on the schedule. One example is transfer of module completion to the field, which added cost and additional work to the field schedules. The FCO work that was planned to occur in the fabrication shops could not be completed there, which compounded the impact of the delays." *Id.* at 10. Additionally, in the Section "Engineering Quality and Rework" the document sets forth the following: "[f]ield engineering corrections and clarifications have been required to resolve a larger number of issues than anticipated. This development also impacted both cost and duration." *Id.* This document proves that Strub's testimony is disingenuous at best. As such, Strub's testimony is not given any weight.

1236. The Human Interface Group (HMI) was not able to get the work done due to time constraints resulting from the project schedule, lack of cooperation and sheer volume of problems. Additionally, they were not given the resources needed to accomplish the job. Ex. AT-406. The HMI group and the SR group did not have a good working relationship. Ex. AT-433 at 40.

1237. When reconfigured PS 9 came online, alarms on TAPS increased from 9700 to 27,000. Ex. AT-433 at 31. The alarm increase was significant since the other reconfigured pump stations had not yet come online (PSs 3, 4 and 1). *Id.* In addition, the activation of PS 9 added over 274 new screens for controllers to view. *Id.* at 29. The Controllers continued to report their concerns regarding the design they inherited for the control system. Heibert expressed concerns about the number of screens added under the SR Project, the design, implementation, and testing of the changes to the control systems. Ex. AT-433 at 30. In addition, she asked for both the design and testing data that led to the increase in the number of screens and they were not provided. Ex. AT-433 at 30 (Tr. 126:5-13).

1238. The HMI Work Group Progress Report noted that there was a 269% increase in the alarms just from the deployment of reconfigured PS 9. It also reported that the alarm system was not fit for purpose. Ex. AT-532 at 2. The report made a comparison of alarms at other locations as follows: 35 alarms at a nuclear submarine; 2000 alarms at VMT Power Vapor; 5000 alarms at a nuclear power plant; 9200 alarms for the entire pipeline F370 system before the S/R project; 17,000 alarms current P/L with the addition of SIPPS, PS09; 35,000 alarms with full S/R implementation. *Id.* The controllers were not satisfied with the system. Ex. AT-516 at 4. At least 18 controllers and four supervisors all agree that "this tool is not equal to the task." *Id.* at 5.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1239. Hiebert's deposition testimony states that after reconfigured PS 9 started, she reported to M. Joynor (currently the VP of Operations for Alyeska) that in a 24-hour period, the system generated 120,000 alarms for PS 9 alone. Prior to SR, the number was about 2000. Ex. At-433 at 36.

1240. The Monthly Pipeline Alarm Summary for the period October 1, 2007 to October 31, 2007, showed the peak flood event goal of less than or equal to 20. However, for the last month they had 13,590 peak flood events, for the quarter the reported peak flood events were 55,203. The percentage time in floods for the month was 30.88 and for the quarter 43.60. Ex. AT-430 at 52. For September 1, 2007 through September 30, 2007, the Monthly Pipeline Alarm Summary again shows a goal of 20. The peak flood events for the last month are 1,207, and for the quarter 55,203. The average time in flood is 30.23 for the month and 43.60 for the last quarter. Ex. AT-430 at 54. For July 1, 2007-July 31, 2007 the monthly pipeline alarm summary shows a goal of 20. The peak flood events are 55,203 the last quarter are 24,255 the percentage time in floods is 65.71 for the month and 52.63 for the quarter. *See also* Ex. AT-480-487.

1241. It is found, that as discussed above, there is further evidence that budget management was poor throughout the execution phase. The audit cited above which reviewed the SR project from 2002 to 2006 concluded that there is no effective "audit trail" which creates uncertainty as to the validity of the data in the G/L and raises concerns regarding the reliability of financial data used for project management. Ex. SOA-387. Additionally the audit found that project controls for the SR AFEs did not provide "assurance to Alyeska management that SR costs were being properly captured and reported. This made it difficult to trace SR project transactions, and "invoiced and paid amounts may not always be consistent with the terms and conditions of the TAPS contracts, and supporting documentation is not always included with the invoice or is incomplete." *Id.* at 2-3. Further, the SR costs may not be captured as capital or expense consistent with FERC and GAAP accounting requirements. *Id*. at 3. This evidence is not supportive of a reasonable utility or prudent manager.

1242. The Carriers allude to a Department of Natural Resources Document (DNR) letter to bolster their claim that the PMT was qualified and that Monthei was endorsed by the DNR.[562] Ex. ATC-380 at 2. However, the letter welcomes the reorganization of the SR project. As the State correctly asserts, the letter, is a reflection of Barrett's poor management of the project, rather than an endorsement of his successor, Monthei.

1243. The project was not being properly managed at this time contrary to the Carriers' assertions. An internal audit of the SR project concluded that "[t]he internal controls evaluated within the scope of this audit were not satisfactory." Ex. SOA-387.

[562] Carriers IB 167.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Conclusions 2007

1244. In this time frame they still do not have a full scope for PS 4 and 1. That is over 3 years into the project. This late into the project they do not have a good estimate of the amount of construction remaining at PS 1 and 4. "A great deal of work remains to have a robust project execution plan and AFE quality estimate for the remaining scope of work at these two locations." Ex. SOA-279 at 16-17. This is not consistent with a reasonable utility manager. As a result, it is concluded that the Carriers were imprudent.

1245. Evidence in the record, Ex. SOA-387 at 4 and considered an admission against interest, shows that detail engineering began after project sanction in contravention of industry standards. The actions of the Carriers were not those of a reasonable utility management.

1246. HMI projects were delivered before completion and PSs went live before those projects were finalized. This was the result of a combination of factors including the project schedule, lack of cooperation, volume of the problems and lack of sufficient resources.

1247. Alarms were not manageable they were coming in "floods." Ex. AT-523. The HMI Work Group Progress Report dated March 31, 2007, is found an admission against interest. Consequently, it is concluded that the alarm system is not fit for purpose. It is also concluded, that the Carriers did not follow industry standards to design and implement this system and thus these actions were not the actions of a reasonable utility manager and were imprudent. Consequently, the costs for the alarm system are not recoverable in rates either under the prudence or use and useful standard. (*See* discussion below on use and useful).

1248. The Carriers failure to halt scope growth led to problems which persisted throughout the execution of electrification. The project continued to experience problems with late drawings and voluminous drawing revisions. Adams testified that "over 100% of the SR project's "drawings were revised or issued after the second supplemental funding request" that was finalized in mid-2005. Ex. SOA-275 at 110:15-16 (citing Ex. SOA-121 at 9 (AFE S320)). Adams also testified, "[e]xcessive drawing revisions . . . is an indication of a project with insufficient definition at sanction and excessive scope creep and design changes." Ex. SOA-275 a t 110:12-14. This Adams' testimony is given significant weight.

1249. Contrary to the Carriers' arguments, as discussed above, the Avons did not need to be replaced as a life cycle replacement starting in 2007. The record does not support this. In their reply brief the Carriers contend that Alyeska in 2007 informed the Carriers that "the main TAPS pumping equipment will need to be reconfigured within approximately seven years. Carriers RB 97 (citing Ex. ATC-384 at 8-9). This exhibit is the request for funding for PS 4 in December 31, 2007. At this point in time, Alyeska claims that there

20140227-3052 FERC PDF (Unofficial) 02/27/2014

are difficulties finding spare parts of sufficient quality and the inability of the system to function at the lower through-put levels now forecast. However, this 2007 determination cannot be used as the basis for a prudence analysis for a decision that was undertaken in 2003 or earlier. Further, the record evidence does not support that there were not sufficient quality spare parts or that the Avons could not be used at lower throughputs or that the Avons were obsolete.

1250. The evidence also shows that the economic analysis at this point in time, is using sunken costs and negative consequences of cancellation/delay alternatives. Ex. SOA-279 at 13. This is deemed not to be the actions of a prudent utility manager. Moreover, the evidence shows that they knew the economics of the project were eroded. "The current full cycle economics have decreased considerably with an AARR of 11% and NPV of -$14.6 million (PI 0.8, 12 years breakeven)." Ex. SOA-279 at 13.

10. What happened in 2008

January 2008

1251. In the justification for the fourth supplement to AFE S020, Conoco relates that Supplement 1 was approved in the third quarter of 2004 to account for power supply scope changes at PS 1 and 9. Supplement 2, was approved in the fourth quarter of 2005 for "various regulatory changes, resource constraints, incomplete engineering, inefficient project execution and inadequate project controls." Ex. SOA-218 at 3. Supplement 3, was approved in the third quarter 2007, for the completion of PS 3. *Id.* Supplement 4, is to complete all remaining work including completion of work at PS 4 and 1 (including completing construction, functional check-out, commissioning and start-up). *Id.* The supplement also includes work to finalize all security, fencing and grading work. *Id.*

1252. Conoco further asserts that when the project was sanctioned following preliminary engineering, only approximately 15% of detailed engineering was complete. *Id.* at 4. Long lead material was ordered immediately after project sanction to achieve the fourth quarter start-up. The 2004 and 2005 project and schedule overruns were due to: "expedited schedule drivers, inaccurate regulatory commitment assumptions, inadequate project management processes, uncontrolled scope changes and delayed operations input to the project execution plans."[563] *Id.* Operational requirements identified at conceptual/preliminary engineering were incorrect, "most notable of which were those associated with the Brownfield Facilities and interconnect requirements to the Greenfield Facilities. *Id.* at 4. Further it points out that established project management and control processes were not used, and the Alyeska/Owner processes used by the seconded project management team was also ineffective. *Id.* at 4. Scope changes did not follow management of change processes and the magnitude of the scope changes were not

[563] *See also* Ex. SOA-210 at 8. Front end loading was incomplete. *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

recognized in time to add resources to assure the contractor's ability to deliver. Moreover, "delays were experienced due to equipment failure to pass initial vibration testing criteria." Finally, the document notes that the project was hampered by Alyeska's operations organization's lack of active engagement, required to evaluate and understand the impacts of the added Brownfield work. *Id.* The final S020 project total according to this document is $597.7MM. *Id.* at 7.

1253. "The previous supplement was based on contractor estimates-that assumed engineering was 90% complete (excluding field engineering and software automation). It has subsequently been demonstrated that engineering progress was less than reported, variously estimated in the range of 50-70%." *Id.* At 8. Conoco points out that over 100% of the projects drawings have been issued or revised since the previous funding request. "Based on the reported engineering status, construction mobilization occurred sooner than it would have if actual engineering progress had been known." *Id.* at 8-9. This resulted in reduced construction productivity and slower progress than planned, which caused additional delays. *Id.* at 9.

1254. Concerning the 2005 new project management team (established at supplement 2) the document reports that they lacked SR and large project experience. Moreover, the project staff was not enhanced to compensate for project control shortfalls. "The project control tools consisted of unmanageable spreadsheets instead of a specialized, industry proven cost and schedule tracking system." *Id.* In terms of engineering delays one execution strategy was revised to allow module completion in the field. This added costs and additional work to the field. For instance, functional check-out planned to occur in the fabrication shops could not be completed there, which added to the delays. *Id.* at 9. Productivity in cable pulling and electrical areas was not up to par. This was due to late engineering, late equipment and material delivery, transfer of work to the field, the degree of difficulty in the cable tray design and work reprioritizations. *Id.* at 10.

1255. The full cycle economics of the project according to Conoco increased from Supplement 3 but decreased considerably since Supplement 2 with an AARR of 11% and NPV of -$12.8 million. *Id.* at 12. The point forward economics, AARR of 23% and NPV of $15.3 million are positive in large part due to the sunk project costs and negative consequences of cancellation/delay alternative. *Id.* at 12.

1256. The document titled Process Safety Performance Metrics Description, shows that during this period there is an increase number of pipeline shutdowns. The document describes why it is important to record shutdown events. Ex. AT-497 at 3. There is a description of the potential problems from shutdowns and restarts. These include changes in the hydraulic gradient of the pipeline which may lead to surges, slack line developments/closures creating undesirable stresses on the pipe and valves coming loose or anchors tripping or repetitive oscillations inducing stress fatigue in the pipe over long periods of time etc. Ex. AT-497at 3. After the SR equipment was installed and

20140227-3052 FERC PDF (Unofficial) 02/27/2014

beginning in 2007, the number of shutdowns increased significantly.[564] Ex. AT-495. For instance in 2007 there were 38. *Id.* In 2011 there were 41 and up to July 31, 2012, there were 26. Ex. AT-499 at 3.

February 2008

1257. Pump Station 3 is completed in February 2008.

1258. A draft Supplemental Finance Memorandum from BP describes the new request for a total of $661.4M ($414.0 already sanctioned $247 new requirement). Ex. SOA-351.[565] The document describes SR as an infrastructure renewal project. It states that PS 9 has electric power supplied by the local utility grid. *Id.* at 2. PS 3 started in December 2007 and relies on self-power generation by new gas-fired turbo-generators. Mechanical completion of PS 4 is targeted for 4Q08 with start-up in 1Q 2009. The document states the project is now 70% complete and there is high hope for the estimates. It states that final project completion has been delayed by three years since originally envisioned, but "the full forecasted savings will be delivered, albeit at a delayed pace." *Id.* at 3. The previous problems have been addressed by the sequential approach and implementation of rigorous project cost control systems. *Id.* The new economic assumption is that maintaining the legacy equipment would have increased costs by 25% (in the status quo case) along with Avon replacement in 2015. *Id.* at 4. The document states that the new equipment has better turndown than the Avons allowing operation at lower minimum throughput levels and longer NS production life. *Id.* This has "been incorporated into BP's reserve bookings." [566] *Id.* According to BP, its "investment of $241 mm of capital …to create $131mm of integrated value to BP group (upstream and mid-stream)." "The State's net share of benefits is $43mm through increased royalty, production and unitary taxes, while $111mm goes to the federal government (net) through income taxes." *Id.* "Based on a combination of the economic benefits of continuing, along with the regulatory, legal and political implications of stopping or deferring, the most appropriate course of action is to continue the project." *Id.* at 5.

[564] The JPO reported there were few shutdown events prior to 2007. In 1998 there were 5, in 1999 there were 18, in 2000 there were 6, in 2001 there were 13, in 2002-2004 there were 8, in 2005 there were 5 and in 2006 there were 15. Ex. AT-500.

[565] Sunk costs are $457.2mm as of January 2008. *Id.* at 9.

[566] This is a producer affiliate consideration with no current ratepayer benefit.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Q&A Speaker Notes for D. Suttle's Phone Conversations with TVPs, OpCo & RCM- February 27, 2008

1259. In this document, the background section shows the number of employee reductions with SR as 285 personnel.[567] Ex. SOA-353 at 6. There is a discussion of the link between "Turndown and Reserves." For instance, the Avons had limited turndown ability (circa 400 MBD due to turbine emissions opacity). *Id.* at 8. The new VFD electric pumps can be operated at much lower throughputs. "This mechanical turndown ability (combined with future investments in line heaters, more pig launchers/receivers, water management, etc.) is an enabler to book more reserves than would otherwise be possible." *Id.* "All of these modifications should allow TAPS to operate down to ~135 MBD." It further asserts, "BPXA has already incorporated this lower hydraulic limit into the basis for its reserve bookings." *Id.* Further, in parenthesis "(SMOG tariff forecasts include SR investments plus future low-flow investments in the determination of when upstream oil production becomes cash-flow negative at a given oil price)." *Id.*

1260. The contributors to the first supplement in the 4Q05 are listed, the following caused design changes: fire marshal refusal to allow de-classification of some buildings without major structural modification, Project Team initiated Process Hazard Analyses and operability studies. Additionally, engineering took longer than expected because of design changes, material costs increased, materials deliveries took longer than expected, civil construction costs were higher (site prep and pilings) and increase in the schedule caused increase in project management costs. *Id.* at 11. These resulted from underestimated costs for labor, material and equipment, additional scope, material and equipment not in the original estimate, engineering and construction errors. *Id.*

1261. The reasons stated for completing the pump stations sequentially were: that there was no camp space at Prudhoe because of increased North Slope construction activity, there was an industry-wide shortage of skilled labor and project controls mitigated this by concentrating on a single worksite, design issues in field could be resolved quickly with a staff at same site, the lessons learned from each pump station could be shared to improve productivity and preemptively address issues at the remaining pump stations. *Id.* at 14.

1262. At this time PS-9 and 3 are in operation. However, PS9 has "minor vibration in new piping system." *Id.* at 16. PS 3 has "some cold-weather T/G issues". *Id*

1263. "Lessons Learned after the first supplement are applied to second supplement." *Id.* at 17. The root causes of the overrun were among others: construction inefficiency resulting from multiple sites; incomplete engineering (design errors). *Id.* at 17. The tradeoff was lower construction / FCO / Commissioning costs vs. higher PMT costs (longer duration)." *Id.* The document states that at this point in time 125 employees

[567] The document is not dated but the Joint Chronology dates it as February 27, 2008. Ex. J-2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

have left. *Id.* In addition, the document states that unidentified scope and materials, underestimates (labor costs, material/equipment costs) and inefficiencies are drivers of the cost increases in the second supplement. *Id.* at 18.

March 2008

1264. D. Suttles from BP, writes a letter dated March 31, 2008. Ex. SOA-352. In the letter again SR is described as an infrastructure renewal project, for low-cost operation, by eliminating future maintenance and outdated equipment, and a new regional oil spill response. *Id.* The letter attributes the project cost growth to construction productivity impacts, incomplete early engineering, design issues, tight craft-labor market conditions and sector inflation. *Id.* Additionally, the letter acknowledges that costs have increased threefold since the original sanction. However, it states that the point-forward economics are robust and if "the project were stopped or delayed, there would be substantial reputational impacts to mitigate, as well as a significant loss of value." *Id.*

Exxon Project Review - March 12, 2008

1265. An Exxon Electrification Project Review, dated March 12, 2008, states that the purpose of the $16m (EMWI) supplemental funding is to complete PS 4 and begin PS1 project planning. Ex. SOA-212 at 2. At this point in time, PS 9 (started up 2/07) and 3 are (started up 12/07) operational. Site construction at PS 4 is 45% complete and PS 1 is 40% complete. The document also states that "scope/design changes occurring during construction" contributed to increased costs. Ex. SOA-212 at 4. At page 6, the document points out a number of improvements that had taken place since the first quarter of 2007: hired a new program manager; Alyeska hired an outside contractor (Worley Parsons) to strengthen project controls; implemented detailed monthly reviews (weekly project team planning sessions); closed AFE S020 (it required work at all stations at the same time) and required that completion work at each station be planned, funded and implemented sequentially. *Id.* at 6.

Email June 16, 2008

1266. A Conoco assessment of SR, in June 2008, describes the reasons for the cost and schedule overruns as due to "gross engineering underestimations, lack of project control expertise, additional work from inefficiencies and from the Alaska regulatory agencies and lengthened schedule." Ex. SOA-293. This happened after the project began and added time and schedule to the forecast. *Id.*

Email October 21, 2008

1267. An email reports that no one has a lot of confidence in the SCADA system right now… Ex. AT-479.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Discussion 2008

1268. Exxon found that scope changes during construction contributed to increased costs. Ex. SOA-212 at 4. This is determined to be an admission against interest.

1269. The monthly pipeline alarm summary for the period November 1, 2008 to November 31, 2008 shows a goal of less or equal to 20. The peak flood events are 2,933 for the last month and 3,811 for the last quarter. The percentage time in floods is 30.94 for the last month and 27.30 for the quarter. Ex. AT-430 at 56. The average number of alarms in November 2008 was 8299.16, the peak 20,313 alarms per period. Ex. AT-481 at 151.

Conclusions 2008

1270. It is concluded that the listing of things that were wrong with the project is an admission against interest. Ex. SOA-218. This exhibit also shows that the economics of the project have eroded. The full cycle economics have an AARR of 11% and NPV of -$12.8 million. *Id.* at 12. The point forward economics are positive in large part due to the sunk project costs and negative consequences of the cancellation/delay alternative. *Id.* These point forward analysis are superficial and not validated by underlying data. They are really at a "high level" and thus not given any weight. The full cycle economics is more indicative of reality but also not validated. It is also concluded that the actions of the Carriers are not the actions of a reasonable utility manager.

11. What happened in 2009

1271. Pump Station 4 was completed in May 2009.

June 2009

Email June 4, 2009

1272. In an email on June 4, 2009, from B. Sargeant he states that Conoco internally intends to say that the SR project is complete and that work on PS 1 will not be SR, but instead will focus on what is required for lower flow. Ex. SOA-302.

1273. In a June 30, 2009, email P. Liddell (SCADA Supervisor for Alyeska) requests "a high priority" on the "investigation and resolution of the problems identified to date. . . Due to these problems, . . . we are getting the clear message that the OCC is losing confidence in the SCADA system, which as you can understand is not acceptable." Ex. AT-477 at 2.

August 2009

1274. K. Eldridge on August 22, 2009, writes by email that "[w]e received more alarms than is humanly possible to respond to in that time frame. Again the Alarm viewer had to

20140227-3052 FERC PDF (Unofficial) 02/27/2014

be abandoned in the middle of an upset because it was streaming alarms so fast it was no longer helpful to the Controller and instead became a huge distraction. . . . TG-2 shutdown should have been the first alarm in but it was not. . . . Any way you slice it, it was a severe alarm flood that rendered the Alarm Viewer useless at a critical moment and CS 360 should address this type of event." Ex. AT-476.

September 2009

1275. N. Glenny an OCC Supervisor wrote in an email dated September 11, 2009, that it "is not possible to respond to over 1300 alarms in 10 minutes. In fact, during another upset at PS04, PS09 coincidently shutdown but the controller was wading through so many alarms from PS04 that losing PS09 went unnoticed until another controller came over to assist. Since the alarm flooding was too overwhelming to read through them all, it was assumed that PS04 & 09 were shutdown by the only common connection – SIPPS and that was the direction taken for troubleshooting the cause of the shutdowns until GVEA called several minutes later to notify us that they caused the load shed. Even if the Alarm Viewer works flawlessly, the amount of alarms that are generated during upsets are unmanageable." Ex. AT-475.

October 5, 2009 - AFE S120- PS1 Electrification and Automation-Scoping White Paper Final Draft

1276. After studying various options (eliminate, defer and/or adjust portions of the work scope for PS1) the preferred option is to follow the scope of work for S120 as originally intended. Ex. SOA-574 at 4. However, the installation of new electric booster pump drivers will be deferred to a future PWR. Project S120 will install the power and control conductors for the new electric booster pump drivers to the greatest extent possible to simplify the future installation of the electric motor drivers. It will also provide an engineered interface to maintain operation of the existing fuel-fired booster pump drivers. *Id.*

1277. In this document the project team recommends that a future PWR purchase "three (3) 5 MW resistive load banks to commission the S120 12.9MW Siemens Turbine Generator (TG).[568] After commissioning, one (1) each 5 MW load bank should be permanently installed at PS01, PS03, and PS04 to address long-term operability issues by providing an artificial load to keep the Siemens TGs operated at these stations above the low load operational threshold of 60% turbine rating." *Id.* The payback period for this option is never and the IRR is negative. Ex. AT-574 at 26-29.

1278. The option to leave the legacy fuel-fired mechanical turbine pump drivers in place was considered and appeared promising in meeting the project's budget constraint. *Id.* at 4. The option was eliminated from further consideration when "Property Accounting"

[568] A ROM cost to install one 5 MW Taurus TG is $10.1MM. *Id.* at 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

advised that if the new equipment "installed at PS 1 was not placed into service for the transportation of crude oil, the Owners would be required to expense up to ~$91MM (same year) and that none of the write-off would be allowed in the Tariff rate…" *Id.* at 5.[569] PS 1 has four partially installed 12.9MW Siemens TG and associated equipment at a cost of $11MM which would not be included in the Tariff if is not placed into service. *Id.* at 6-7.

1279. The preferred option, due to the asset right off issue, is to complete installation of the Siemens TG at $7.3MM. *Id.* at 7. The option of installing two 5 MW Taurus TGs (with provisions for a third unit) with 3 MW of Continuous power from the local power utility was also considered. *Id.* at 6. This option is the preferred technical option based on currently available information and long-term operational stability. "However, the near term $11 MM write-off expense associated with not completing the 12.9MW TG installation makes this option financially unattractive. *Id.* Note that Appendix D, the Economic NPV analysis of 5 options, shows negative NPVs for all options. *Id.* at 24-29. This includes the preferred option.

Email October 19, 2009

1280. In an email dated October 19, 2009, C. Todd states that the SCADA group is working on a method to start addressing HMI and Alarm Suppression issues. "We cannot continue in 'fire-fighting' mode; therefore, I plan to drive correction and improvements to the SCADA system using more of a project-type methodology." Ex. AT-471.

Discussion 2009

1281. The scope for PS 1 was still being determined in October 2009. Ex. SOA-574. The Scoping White Paper was done to "bring the scope and budget for project S120 (EA) [Electrification and Automation] into alignment … This white paper discusses the results and preferred scope option stemming from this conceptual level evaluation." *Id.* It is incredible that this late into the project they are still doing conceptual level scoping for a project that had to be completed by the end of 2005. It defies reasonableness to do

[569] The financial books show "$58M in Property, Plant & Equipment in 2006 for all modules, pilings, skids and fuel tanks, and $33M in Construction Work in Progress (CWIP) for all the assets that are not complete. The $33M in CWIP would be a direct write-off to expense and the $58M in PP&E would need to be retired with the net gain/loss reflected on each owner's financial statements, in the year the decision is made to scrap the assets." *Id.* at 12. Additionally, the "tariff books show $91M on CWIP with nothing having been transferred to PP&E. Thus, the $91M CWIP would be a direct write-off to expense in the year a decision has been made to scrap the assets. In addition since the assets have never been used to transport oil 100% of the write-off may not be allowed in the tariff rate of the Owners." *Id.*

20140227-3052 FERC PDF (Unofficial) 02/27/2014

"conceptual studies" in the execution phase of a project. This is contrary to industry standards.

1282. They are still working on the alarm management system issues. The project created an alarm system without documenting and rationalizing the alarms added to the UCOS software, resulting in thousands of alarms (alarm floods) annunciating in the OCC after startup of PS09. Ex. AT-430 at 17, 18. Years after the project was sanctioned they are still working on the SCADA system.

1283. DeHaas's email dated April 3, 2009, sheds light on the state of affairs at this point in time. "As for Alyeska, they got and will continue to get what they deserve. This whole upgrade we did (will cost over a billion before done) was unnecessary. It was all led by a bunch of complete and total idiots, or parasites." Ex. AT-449 at 1. In December 2009, DeHaas observed that with the SR equipment, Alyeska has "had a large number of problems, mostly due to lack of attention to detail package design, as well as just some poor design." Ex. AT-451. For instance, according to DeHaas "our locations are remote, and our operations are remote (unattended). The air compressor packages unfortunately were not really designed and furnished with that in mind." Ex. AT-451 at 6.

1284. The record reflects that there are problems with the Safety, Integrity & Pressure Protection System or SIPPS. Privett an instrumentation/electrical technician for Alyeska[570] testified that he is concerned that adequate testing of SIPPS once a program is changed is not being done. Ex. AT-431 at 30-31. He gave as an example issues at PS9 where they will check out the fire systems (fire commands go to SIPPS) and SIPPS takes certain actions, "and everything will be working and then a download is done to modify the program and then the system does not work anymore." Ex. AT-431 at 30. He further states that after modifications are made to the SIPPS program, retesting is not done afterwards.

1285. Significant incidents on TAPS have occurred at PS 9 after SR. This includes a TK-190 overfill near loss on March 22, 2007; the Energy Isolation Near Loss Events in October 2008 and the Piping Overpressure Event on July 19, 2009. Ex. AT-410 at 9.

1286. Two 5 MW Taurus generators with electric power from the local power utility was the "preferred technical option based on currently available information and long-term operational stability" at PS 1. Ex. SOA-574 at 6. This would remove the need to install the 12.9 MW Siemens turbine generator and simplifies the design and long term O&M costs. *Id.* at 6. "By using a mix of reduced capacity generators and utility power, long-term operational stability can be provided without the need for future PWRs to address

[570] He has had a long career at Alyeska and worked at almost every pump station, both as an operator, and in senior and lead technician/step-up roles. In 2005, he became lead instrument technician on the SP Commission Team at PSs 9, 3, and 4.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the 12.9 MW Siemens TG turbine turndown issues related to reduced throughput rates.[571] From a technical standpoint, this option provides the best long-term flexibility and scalability in the PS01 power generation configuration at currently understood throughput projections." The white paper recommended, due to the low-flow projections for 2009-2014, the installation of 5 MW load banks at PSWs 1, 3 and 4 to provide an artificial load to the Siemens TG operating at these stations above the low-load operational threshold of 60 percent turbine rating. Ex. SOA-574 at 18. Anadarko is correct that the due diligence that should have been done prior to sanction was done five years later. The record reflects that the conclusion five years later is that electrification as implemented was inefficient.

Conclusions 2009

1287. BP admits that one of its incentives for SR was to book more reserves.[572] Ex. SOA-11 at 17. *See also* Ex. SOA-353 at 8. This document also shows the relationship of the Owners in the tariff determinations on TAPS. *Id.* Further, the reason the legacy equipment was not kept at PS 1 was because if the new equipment installed at the pump station was not placed into service the Owners would have to expense $91MM and this write-off would not be allowed in the tariff. Ex. SOA-574. The State is correct that the recommendation was to install the electrified equipment from the original plan rather than the legacy equipment, in order not to lose recovery of $91 million. SOA IB 128. Further, the State is also correct that the new equipment was oversized and the team recommended a 5 MW load bank at PSs 1, 3 and 4 to address long-term operability issues by providing an artificial load to keep the Siemens TGs operated at these stations above the low load operational threshold of 60% turbine rating.

1288. The issues with the SCADA system are ludicrous. This is the system that the Bailey report had recommended improving. The Carriers knew Bailey had recommended updating automation.

1289. As Anadarko correctly points out[573] the October 5 study (PS 1 Scoping White Paper) confirms what was determined when TAPS was originally built in the 70's and again in the 90's (Bailey) that electrification of the pumps was not economical and created operational problems. Moreover, the Carriers rejected the best technical options for PS 1 because of sunken costs with no economic analysis of the situation. The

[571] The 12.9 MW Siemens (the original scope) pose "long-term flexibility/scalability challenges" related to operating the Siemens as declining throughput rates cause air quality emissions to approach low load operational thresholds. Ex. SOA-574 at 7.

[572] This is a producer affiliate consideration with no current ratepayer benefit.

[573] Anadarko IB 145.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Carriers' decisional process was skewed by tariff considerations. The decision to reject the best technical option based on financial considerations of recovery of sunken costs without further analysis is not the action of a reasonable utility manager and is thus considered imprudent.[574]

1290. The evidence in this case is fascinating. To wit, and regretfully one of the most expressive people in the case was not cross examined. However, his statements are so eloquent that merit repeating here, since he succintly summarizes the essence of this case: "As for Alyeska, they got and will continue to get what they deserve. This whole upgrade we did (will cost over a billion before done) was unnecessary. It was all led by a bunch of complete and total idiots, or parasites." Ex. AT-449 at 1. In December 2009, DeHaas observed that with the SR equipment, Alyeska has "had a large number of problems, mostly due to lack of attention to detail package design, as well as just some poor design." Ex. AT-451. For instance, according to DeHaas "our locations are remote, and our operations are remote (unattended). The air compressor packages unfortunately were not really designed and furnished with that in mind."

12. What happened in 2010

March 2010

1291. The Office of Pipeline Monitoring required Alyeska to correct significant concerns and issues with the electrical power supplies at PS3 before de-manning the station. Ex. AT-426. The letter notes that within the last 15 months there have been more than 25 unscheduled slowdowns originating at this pump station. It notes that the Bureau of Land Management (BLM) is concerned that a lack of sufficient on-site support personnel at PS-3 combined with severe weather conditions could prevent the continued operation of the pipeline if an unplanned shutdown should occur and the situation could not be

[574] The Carriers in their RB argue that since PS1 is not part of this case the PS 1 Scoping Paper cannot be considered. Carriers RB 99. This argument is meritless. The scope of this project since its inception included PS 1. This case is about the prudence of the project. They also argue that the follow up White Paper regarding the cost of continuing with the legacy equipment at PS 1 was not mentioned by the protestants. However, the document cited by the Carriers, "Maintaining Legacy equipment Considerations-PS01" "Summary Paper" states that it is a cursory level evaluation. Ex. ATC-389. As such, this document is not given any weight. Moreover, the follow up document is dated after the white paper which had recommended going ahead with electrification based on the sunk costs not being able to flow through the rates if the project was not continued. Thus, the follow up document dated October 27, 2009, could not be considered support for the recommendation.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

remotely resolved. *Id.* The list of issues is on page 2 of the exhibit and one of the issues noted is the "[d]esign of the turbine generators for manned operation."[575] *Id.* at 2.

1292. In March 2010, the Office of Pipeline Monitoring sent a deficiency letter to Alyeska concerning PS 3. Ex. SOA-714. The pipeline was instructed to correct the deficiencies prior to de-manning the station. "Resolution of the deficiencies will be demonstrated when turbine and related equipment reliability and availability at PS-3 equivalent to or exceeding tha[t] of PS-4 has been demonstrated for an acceptable period of time." *Id.* at 4. A number of issues were listed, among others, "excessive generator trips and pipeline slowdowns", design of the turbine generators for manned operation.[576] *Id.* at 2. "This report concentrates on known and generally acknowledged issues and problems with the turbine generators and related equipment at PS3. Other issues and concerns include the continuing trips of the turbine generators and mainline pump units, unresolved issues with the TG air compressors, ventilation systems, lube oil coolers, and resolved issues and uncompleted work on the fuel gas system supplying the turbine generators." *Id.* at 4. *See also* Ex. SOA-715.

1293. The document indicates that there is one operator stationed at PS-3. The author of the document states that 2 people are necessary for a number of functions including any significant work in winter. *Id.* at 13. "An emergency near PS-3 would require a response from someone at PS-4 which could take an hour or more during less than ideal winter weather." *Id.* at 14.

1294. The document concludes that there are numerous corrective actions and issues to be resolved before unmanned operation should be permitted at PS-3 during winter months. "Although this pump station has been in operation for over 2 years it has yet to demonstrate reliable "hands-off" remote operation. Until such time as the known and new deficiencies and issues are correct constant manning by two or more qualified technicians and/or operations personnel should be required." *Id.* at 14.

1295. "Black start" generators for PS 3 and 4 were scheduled to be completed early in 2010. These generators can provide restart capability in the event of a total power loss. Ex. AT-420. *See also* Ex. SOA-714 at 4.

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[575] Since May 2005 the Carriers were aware that other users were experiencing problems with the Siemens turbines. Ex. AT-425.

[576] "In reviewing the purchasing specifications for the turbine generators it was noted that unmanned/unattended operation was not included as a performace requirement. Since turbine generator installations are generally installed in the environments where attendants are on site the requirement for unmanned operation should be included as a performance requirement. Siemens is reported to have cited the lack of a requirement for unmanned operation in meetings with APSC but the BLM has yet to verify any discussions between the two parties on unmanned operation." *Id.* at 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

May 2010

1296. The JPO sent a notice to complete the SR drawings and documentation for PSs 3, 4 and 9, on May 7, 2010. At this point in time, PS 9 was completed and the startup occurred February 2007 ("27 months ago"); PS 3 December 2007, ("17 months ago"); and PS 4, April 2008 ("11 months ago"). EX. AT-427. The notice indicated that there was a prior agreement which required Alyeska to update drawings and documents for critical systems within 180 days. *Id.*

June 2010

1297. The TK-190 Overfill Incident Root Cause Analysis Report and Post Accident Review dated June 22, 2010, describes that on May 25, 2010, during a scheduled short duration shutdown of TAPS, PS 9 experienced an unrecognized relief event. The event resulted in overfilling of Breakout Tank 190 (TK-190) and a product spill into a secondary containment. The primary power and redundant power outage to the Control Module caused the critical station control systems to shutdown: SIPPS and others. In addition, the tank farm audible and visual evacuation alarm did not function as a result of the loss of primary power and the loss of SIPPS. Ex. AT-410 at 3 (same exhibit AT-262). The pipeline was restarted approximately 77 hours after initial notification and volume spill was approximately 4,500 barrels of Alaska North Slope Crude Oil. *Id.*

1298. Root Cause # 1 for the incident were several technical and design issues. *Id.* at 11. Thus, there are operational issues in the reconfigured pumps. "The PS09 Caretaker had multiple roles during the shutdown. The Caretaker was the process representative, one of the maintenance technicians assigned to perform the fire system testing, and the Operations single point of contact (SPOC) for the project F645, the PS09 D2 Valve Replacement." Ex. AT-262 at 6. "An Alyeka Valve Program Engineer was on site at PS09 to support the BL-1 valve testing…" *Id.* Further the document points out that there are expectations for maintenance and response personnel to fill some of the roles historically performed by operations personnel. "In the case of the TK-190 overfill incident, one individual filled three roles as the Pump Station Caretaker, Maintenance Technician, and project F645 SPOC." *Id.* at 14. The report also points out that, "PS09 is fully automated and unstaffed, PS03 and PS04 are also fully automated and transitioning to unstaffed, and PS01 has not started the automation process and remains in the legacy configuration. For automated stations, the interconnection and failure modes are complex and can be difficult to troubleshoot. Automation Engineers are routinely consulted to assist OCC and field personnel with troubleshooting activities." *Id.*

August 2010

1299. In an email from K. Eldridge, dated August 29, 2010, he states that "about a month after Nancy and Val were "let into the lab" for the SR HMI project …and saw the HMI and wrote 70 issues and then immediately became unwelcome guests . . . that's when the fight started .. . It has been four years now that we have been slamming our

20140227-3052 FERC PDF (Unofficial) 02/27/2014

heads against the wall . . . So you can understand why none of us are eager to get back involved? Our reputations were discredited, our characters were assassinated, we were personally attacked and our peers were turned against us . . . yet we prevailed onward and every time we regained enough energy and strength to bring the issue up again, we would stand up and shout only to be knocked down or completely ignored. . . We are simply exhausted from battling not to mention the toll it has taken on our careers and health and we are extremely frustrated with the lack of support from above, . . . HMI and Alarm Management improvements never made it to Vegas . . it died on the side of the road…K." Ex. AT-536 at 2.

October 2010

1300. AFE 120 was submitted to the Owners on October 13, 2010. Ex. ATC-391. The AFE request additional funding to complete the PS 1 work originally authorized as part of AFE S020. *Id.* Additional engineering design, planning, and estimating in 2010 resulted in the identification of additional work, and the need for an extended project duration. *Id.* at 3. The work will last until July 2014. *Id* at 3 and 12. The AFE is to complete design, construction, inspection, functional checkout, commissioning and startup of the "approved Electrification and Automation scope of work at PS01, first initiated in 2003." *Id.* at 6. The AFE continues on to state that S120 will not replace the legacy equipment (booster pumps) with electric motor drives. The existing booster pumps are fit for purpose and will be replaced on a life-cycle basis as a future maintenance project. S120 will install electrical capacity and cabling to facilitate the installation of the electric motor driven units in future years. *Id.*

1301. At this point in time the "controls and automation designs are near finalization." *Id.* at 11. So again they are embarking on construction without completing the design. The document indicates that automation and control issues which were significant concerns in the previous AFEs have been resolved and tested at PS03, 04 and 09. *Id.*

Discussion 2010

1302. The staffing levels at the PS are often driven by pipeline events. D. Hisey testified that staffing levels at the pump stations are driven by Alyeska's staffing strategy based upon regionalized maintenance and oil spill response, automation and pipeline events.[577] Ex. AT-405 at 6, 10.

Conclusions 2010

1303. The evidence in this case shows that years after construction began the Carries had not given the JPO drawings they were obligated to give. Further and more troubling is

[577] Staffing levels are not driven by electrification of the main line units or there are no staffing changes directly attributable to electrification of the MLUs. Ex. AT-405 at 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the fact that design may be incomplete. For instance, Turnipseed testified that the documents about the design are not informed with what is actually installed on the pipeline. He specifically mentioned SIPPS detailed design documents being inconsistent with what's in the field. Ex. AT-429 at 15 (at 71:11-14; 72:15-22). Turnipseed further testified that he believes the detailed design of SIPPS is insufficient, which increases the risk within the system. Ex. AT-429 at 15.[578] Further, the indication in the JPO letters concerning the design of the turbine generators for manned operations is troubling. Ex. SOA-714 at 2.

1304. Further, the current use of the legacy equipment disproves the Carriers' original decision to replace this equipment. For instance, PS 1 is using the legacy equipment. In addition, in November 2010, Alyeska revised the Cold Restart Contingency Plan, and it included a
[CEII MATERIAL REDACTED] Ex. SOA-628 at 8, 16, 19; Tr. 3707:9-3708:9.

13. New state of affairs

1305. According to the State, the operations and maintenance staff at the pump stations has not changed significantly after SR. The State provides a chart with circa 2002 technicians at PS 3 (17), PS 4 (17), PS 9 (15) for a total of 49. After electrification circa 2012 technicians at PS 3 (0), PS 4 (34), PS 9 (14) for a total of 48.[579] Pump Station 3 has electric pumps and the living quarters are closed. However, significant numbers of personnel are housed in an adjacent camp which was in place long before SR. The pump is unattended except for a utility rover (implemented in response to a DOT-PHMSA order). Ex. SOA-699. The "OCC controllers can restart or switch equipment and restart the pipeline in some instances without on site human intervention." *Id.* Response time for human actions is the time required to drive approximately 50 miles from PS 4 to 3 (this can vary based on road conditions and weather). *Id.*

1306. Pump Station 4 has electric pumps and has a maintenance base located adjacent to the SR equipment. It also is unattended except for utility rovers. *Id.* The OCC has the same capabilities for PS 4 as PS3. *Id.* The Galbraith Maintenance base is located adjacent to the new equipment at PS 4. *Id.* at 2. Human response time varies from

[578] "During the pipeline shutdown event on April 7, the TAPs communication systems (i.e., microwave and/or fiber networks) did not fail. The failure was internal to an individual Programmable Logic Controller (PLC) in the Safety Integrity Pressure Protection System (SIPPS). The internal failure caused the SIPPS PLC to lose communication with two remote gate valves (RGVs) triggering activation of automated failsafe actions to shut down the pipeline." Ex. AT-473 at 2.

[579] Exs. SOA-741 (pre-electrification), SOA-697 (post-electrification), pump station 4 includes personnel assigned to Galbraith.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

minutes to several hours depending on the location of the personnel. Maintenance personnel normally work day shift and are on call at night. *Id.* at 2.

1307. The same operating parameters are applicable to PS 9. *Id.* at 2. Maintenance personnel from Fairbanks have been moved to PS9 and live in the adjacent town. *Id.* at 2. Ex. SOA-28 at 24.

1308. An additional issue with the system involves vibration in TG-3702 which "has been above the "Alarm" level for many months. Ex. SOA-715 at 4. Another issue is the tripping of generators and VFDs from "power transient instability." *Id.* Further, there were four instances in 2012 when the blades of the Siemens turbines have been replaced at considerable expense because they have had a shorter life-span than predicted. Ex. SOA-691. Moreover, additional scope items have been added to the project, such as backup power diesel generators because there was a lack of backup diesel power generators in the event of a double failure. Ex. SOA-715 at 5.

1309. Operating expenses associated with personnel have increased since the SR project. Ex. AT-435 at 9 and AT-442. The Carriers have failed to meet their burden to demonstrate that major maintenance has been reduced due to the electrification of the MLUs.

1310. Anadarko argues that TAPS is worse off than before SR. The electric MLUs are more complex than the direct-drive fuel MLUs and require far greater maintenance. Ex. SOA-740; Tr. 8083:8-8084:2. The electric MLUs are less adaptable to the range of future throughput levels than the direct-drive fuel turbine MLUs. Ex. SOA-574 at 19 (at less than 600,000 bpd PS 1 requires 7 MW or less power, and the Siemens Cyclone handles 0% of the load). At current throughput levels, the SR configuration requires five electric MLUs to obtain positive flow, where only two direct-drive fuel turbine MLU's would have been necessary. *See* Ex. AT-490. As of the time of the IBs, every core of the new SR electric turbine generators has been replaced. [580] Tr. 6815:14-17. The core of the turbine generators has to be changed out every 14-15 months since they were de-rated. Tr. 7051. Alyeska has to rebuild the SR turbine generators within Alaska because it is unable to get them rebuilt in a reasonable time by the manufacturer. Ex. SOA-692 at 6-7.

1311. Moreover, the SR turbine generators are improperly sized for current throughput levels and have to be operated above 60 percent capacity in order not to violate air quality control standards. Tr. 8483-8484. In addition, a recent conceptual white paper for PS 1 states that the direct-drive fuel MLUs was a "promising option." Ex. SOA-574 at 4 and 10. This scoping paper also suggested installing a 5MW resistive load bank at PS 1, 3 and 4 to address operability issues by providing an artificial load to keep the Siemens

[580] Anadarko IB 11-12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

TGs operated at these stations above the low load operational threshold of 60% turbine rating. *Id.* at 10.

1312. Contrary to the Carriers' assertion that safety has been improved as a result of SR,[581] Anadarko argues that unscheduled shutdowns have increased significantly since SR even though throughput is at a lower level than in the past two decades. From 1998 to April 2007, annual shutdowns ranged from 5 to 18. Ex. AT-500. Since the start of SR in 2007, the number of shutdowns has increased. In 2011, there were 41 shutdowns which are more than double those in 1999. Ex. AT-499. According to Anadarko this is a 400 percent increase.

1313. The Carriers assert that SR improved the control systems.[582] However, according to Anadarko, alarm levels have increased well over 400 percent since SR and are at a point not consistent with industry standards.[583] Exs. AT-405 at 36; AT-433 at 16; AT-480; AT-481 and AT-483. Since SR has been online, it has not had a single week in which it has achieved the industry standard for the alarms system management. Ex. AT-480; 481 and 483. Tr. 7713:12-20; 7708:1-21. Alyeska amended its control system guidelines by taking out all objective standards for the alarms in order to make the guidelines more "audit friendly." Tr. 7564:5-24.

1314. The Carriers argue that Anadarko is wrong because the average number of alarms has not increased by well over 400 percent since SR. Carriers RB 105-106. The Carriers argue that Anadarko is wrong since post SR there have been less than 2000 alarms daily at PS9. Carriers RB 105. The 2000 daily alarms figure comes from Hiebert who stated that before SR PS 9 could get up to 2000 alarms daily. Ex. AT-433 at 36. They prepared a chart in Appendix A color coding alarms based on the alleged SR standard for PS 9 before SR of 2000 alarms per day. Carriers RB App A. Their own exhibits shows an excess of 2000 alarms per day for the period July1-31, 2007 and over 4000 alarms for the period November 1-30 and December 1-31. This is far in excess of their own standards at the time.

1315. In the periods of time not mentioned, August through October the numbers were above a 1,000 daily alarms. Again well above their own protocols. *See* Ex. AT-466 at 66 (total average alarm rate 5 per hour or ~150 per day). In 2008, January, February, March, August and December are above 2000 per day. May, June, October and November 2008 exceeded 4000 alarms per day. The other months show an average exceeded 1,000 alarms per day. For 2009, January, July, September, October and November exceed 2000 alarms per day. February has 594 alarms. August shows over 1,000 and there is no data

[581] Carriers IB 79-80.

[582] Carriers IB 80.

[583] Anadarko IB 12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

for March through June. December was over 5,000. In 2010, January, February and June are over 2000 alarms per day. February through April exceeding 1,000. May exceeds 4,000 and there is no data for the rest. Carriers RB App A at 2. For 2011 there is no data. Note in this year all three pump stations are operational (the last to become operational PS 4 flowed oil on May 21, 2009). For 2012, January 1-18 exceeds 2000 alarms. January 8-15 exceeds 4,000. January 22- March 18 exceeds 2000 alarms. From March 25- April 2 the number of alarms exceeds 1,000. From April 1- April 29, the total alarms exceed 2000. April 29 to May 6 the total alarms exceed 1000. June 24 through July 1 shows over 3,000 total alarms. July 1- July 29 the total alarms exceed 4,000 and July 29 through August 5 the total alarms are over 2,000.

1316. The Carriers have eliminated their own standards, however, since the standards were based on industry standards, *see* discussion below, the number of alarms to this day exceed, industry standards. Further, the evidence in this case shows that there are problems with the alarm system, including inept alarm management design. Ex. AT-532 at 2. The pre-SR system design of AFE 370 supported 9,700 alarms system-wide. Ex. AT-408. This was the upgrade contemplated in 2002. Thus, the inference is that the pre-SR pipeline had less than this number. "SR UCOS supports 27,000 alarms, 10,000 for PS9 alone with over 600 per mainline unit." *Id.*[584]

1317. Additionally, the Human Machine Interface (HMI) added irrational complexity to the system due to the failure of the design to comply with fundamental HMI design concepts. For instance PS 9 has almost 300 control screens (before SR it was less than 10). This makes positive control of the system under SR less likely during upset conditions. Ex. AT-408. One of the reasons for this design issue is the fact that Hinz was removed from the job and a less experienced system designer from Alyeska took direct oversight of the HMI design work.[585] The Carriers controllers in a progress report

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[584] The Carriers also argue that the OCC controllers are DOT-qualified and that they have a professional obligation to shut down the pipeline if they consider its operation unsafe. This argument is irrelevant to the system design or flaws.

[585] The Carriers argue that Roberts was qualified and had worked with Hinz so it was logical to make him the lead. The support for his prior experience is automating large gas compressors at the Valdez Marine Terminal. Carriers RB 110. It is found that Anadarko's argument is not refuted by this limited experience. Further, the Carriers argue that by the time Roberts was in charge (April 2006), factory acceptance testing of the control system was being completed in Edmonton. Carriers RB 111. This is contrary to the evidence in this record. For instance in a document dated February 2006 which was a summary of an Owners' review it is stated that "completing automation design … appear to be the biggest known outstanding risks." Ex. SOA-320 at 5. Further, it recommends "get alignment behind a clear automation control philosophy, put resident, full-time management team in Hinz, SNC and CSI. *See also* SOA-225. It is impossible that they could be ready for factory acceptance testing in two months. *See* above, what

20140227-3052 FERC PDF (Unofficial) 02/27/2014

dated April 1, 2007, stated that the SR control system is unfit for purpose. Ex. AT-414 at 3. Under upset conditions one operator was unaware that a pump station had gone offline (needed assistance from another operator). Another operator had to abandon his control monitors during upset conditions because they were not helpful to control the pipeline. An oil spill and fire at PS 9 were attributable to breakdowns in the new safety systems. Consequently, Anadarko is correct that the SR project resulted in degradation of the reliability, safety, efficiency, and positive control of TAPS.

1318. In July 2011, the Carriers reactivated the legacy pump and equipment at PS 7 for the purpose of adding heat to the oil stream. Tr. 6771:7-10. This is a permanent recirculation loop at PS7 (ramped down and not electrified). Ex. SOA-607. Howitt testified that this could also be done at PS 1. Tr. 6771:17-25. Pomeroy testified that they were aware of this (that the legacy equipment generated heat which could be used to heat the oil) during conceptual engineering but it was not included in their analysis. Tr. 8108:18-25. As Anadarko points out, the concept implemented by the Carriers ignored the value of the legacy equipment. *See* above, Conclusions 2010.

1319. J. Johnson's staff reductions never came to fruition. The record reflects that third – party vendors not included as staff in the analysis, have replaced any possible reductions in the staff. Tr. 6831:7-14. Additionally, maintenance staff are still living at the PLQ at PS 4 (Galbraith Maintenance Center) and using the facilities. Tr. 6849:5-24. Rovers are working at PS4 "around the clock, 24/7." Tr. 6858:18-21. Technicians are working out of the maintenance base at PS 9. R. 6852:18-23. Utility rovers still work at PS 3 and can either stay at PS 4 (Galbraith Maintenance Center) or at PS 3. Tr. 6877:13-6878:7. Howitt testified he did not know how many people were at Galbraith when he visited the pump station in May 2011. Tr. 6879:2-4. Howitt visited PS 3 for four to five hours and on another occasion stood outside the fence. Tr. 6881:2-21; 6882:23-25. The gate logs for PS 3 contradict Howitt's testimony concerning this pump station.

1320. Anadarko argues that Alyeska's O&M costs have not been reduced. Alyeska spent on O&M[586] $345 million in 2003, $337 million in 2004, $337 million in 2005, $357 million in 2006, $375 million in 2007, $377 million in 2008, $374 million in 2009, and $360 in 2010. Ex. AT-248 at 1. O&M costs are projected to increase from $368 million in 2011 to $400 million in 2015. Consequently, the cited figures show that O&M costs have not been reduced. *Id.*

1321. PS 1 has not been reconfigured.

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happened in 2006 which supports the finding that automation was having issues all through 2006. Thus, Roberts testimony in this regard is not credible.

[586] This does not include amounts for fuel power, and drag reducing agent, since, they are highly variable, and a reduction in operations and maintenance personnel would not have an effect on these items. *See* Tr. 3951:25-3952:4.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Discussion

1322. The SR project is not scheduled to be completed until July 2014. As the record shows, as of March 2011 $707.8 million have been spent on the project which is still not complete. The estimate for PS1 completion is $77.9 million, thus the total cost of the project will be approximately $786 million. Ex. SOA-546 at 7:4-8. However, these figures do not include the costs incurred by Alyeska in taking over the project in 2005 in order to attempt to complete it. Thus, Anadarko is correct, that the true costs of the project will never be known. The costs of SR significantly exceeded the 2004 LRP SR project cost projections. Ex. AT-441. Grasso added 10 percent to Alyeska's baseline personnel cost for the period 2004 through 2009 to absorb what Hisey believed was a minimum estimate of the amount of time, on average Alyeska employees[587] were involved with SR implementation. Ex. AT-405 at 24. Consequently, the actual cost overrun is substantially more than originally estimated.

1323. As of the writing of this decision the SR project is not complete. Pump station 1 is operating with the legacy equipment and remains fully staffed. Ex. SOA-699. The legacy equipment at PS 1 is operating at or below 6100 rpm for extended periods of time. This is below the "previously defined minimum operating speed of 6400 rpm." Ex. ATC-917 at 36:3-6. This fact belies the Carriers contention for undertaking SR, that the legacy equipment had to be replaced because it could not operate at lower throughputs. Moreover, they automated the ramped down stations which is essentially the Hybrid approach. Thus, it is concluded that this is contrary to their argument that Hybrid was not cost effective. The inference that can be made is that electrification was not necessary and was made to benefit the affiliate producers. To increase the value of a totally depreciated asset and benefit the affiliate producers cash flow. The statement in Ex. ATC-391 at 6 that the legacy equipment is fit for purpose is an admission against interest. Ex. ATC-391 at 6. *See also* Ex. SOA-574 at 4. The project was not undertaken because the legacy equipment had to be replaced.[588] Work on PS 1 was stopped in 2006 and has recently been restarted now called Electrification and Automation or EA, the work on PS1 is expected to be completed in 2014, over nine years after the original SR schedule showed delivery of the turbine generators to the site. Ex. AT-421 at 15.

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[587] Costs of SR related projects worked under Alyeska baseline budgets are not included. Tr. 3984:15-3985:23.

[588] In the RB the Carriers assert that the new SR facilities are more appropriately sized for current and expected throughput levels than the old Avon gas generators that they replaced. Carriers RB 19. They cite Howitt, the JPO 2008 report and the testimony of M. Thompson the State Pipeline Coordinator in support of this proposition. Howitt's testimony in this regard is not corroborated and not given significant weight. The JPO report itself and Thompson's testimony have the caveat that the information given by Alyeska is not independently verified and not corroborated. Tr. 2536:1-9.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1324. PS1 is the largest and most complex PS, with more major systems than any other operating station. Tr. 7335:17-19 (Howitt); Tr. 8443:21-23 (Johnson); Tr. 7613:10-13 (Church); Ex. AT-431 at 10-11 (Pivett describes in detail some of the complexities of PS1. In addition, to the power generation and mainline units in the other PS (except PS 5), PS 1 had two 220,000 barrel storage tanks with an inert blanket gas and vapor recovery system, gas flare, pig-launching facilities, gas compression facilities, metering, and ground refrigeration systems. Ex. AT-405 at 22. *See also* Ex. AT-431 at 11 and 34. Thus PS 1 will be costly and involve more risks than the other PSs and the largest challenge of SR. *Id.* at 34. Moreover, it is concluded that Anadarko is correct that the risks are not justified by the alleged savings ($84 million projected).[589] A 2009 study[590] found that installing the Siemens TG at PS 1 would provide "relatively low financial savings potential in terms of installed equipment" and "[would pose] long-term flexibility/scalability challenges related to operating the 12.9 MW Siemens TG as declining throughput rates cause air quality emissions to approach low load operational thresholds." Ex. SOA-574 at 7. The study concluded that the payback period for this option was "never" and the IRR was "negative." Ex. SOA-574 at 26-29.

1325. As it stands today, there is no credible evidence in this record that the pump stations can be totally de-manned which was how they were to garnish savings through automation. As Ex. SOA-714 points out, the turbine generators were designed for manned operation. Ex. SOA-714 at 2. The logs-Check-in/Check-Out Any Time[591] provided in this record support the States' position that there were no personnel savings and there are more personnel at the stations now than before. PS 3 was supposed to be completely unmanned. Turnipseed stated that PS 3 is manned and keeps Alyeska people there virtually all the time. Ex. AT-429 at 22. According to Turnipseed, PS 9 is now a manned facility and during the day, it has a full maintenance crew and a full-time baseline crew on staff. PS4 is a fully manned facility, with 24-hour-call-out for immediate response and it has a full maintenance crew and a full baseline crew. Ex. AT-429 at 23.

1326. Concerning PS 7, Turnipseed stated that "in the winter, when crude oil temperatures are lower, they are now bringing in a crew of retired technicians on contract, or technicians from Pump 5 to provide 24-hour-a-day support at any time . . . there's a potential for the oil temperature to drop below 40 degrees in the pipeline." Ex. AT-429 at 23. Pivett also provided the number of staff on ground support for the SR facilities. Ex. AT-431 at 13-19. *See also* Ex. ATC-917 at 25. Pivett stated that there is no difference between the current term "utility technician" and an operator prior to SR.

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[589] Ex. AT-421 at 16. Based on the evidence in this case any such projection is suspect.

[590] Alyeska/Caltech-Senex Study. Ex. SOA-574.

[591] *See*, Exs. SOA-706, 707.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Ex. AT-431 at 18, 13-14. Turnipseed stated that the utility operator looks at systems to preempt the alarm event or the shutdown event, rather than allowing them to reach the point where they would reach alarm or shutdown. Ex. At-429 at 23.

1327. Anadarko witness Grasso analyzed the actual expenses for 2004-2011 and determined that there are no actual savings of personnel expense. Ex. AT-435 at 7-9. As a matter of fact, he states in his testimony that personnel and outside labor expenses have shown a substantial increase from 2004-2011. Ex. AT-435 at 7-9. Further, he testified that actual expenses have substantially exceeded the projected expenses from the 2004 LRP. Ex. AT-442.

1328. Alyeska has previously used a regional maintenance approach called Pipeline Maintenance Team serving TAPS' north, central and south regions, later reorganized into a line-wide maintenance team. Anadarko correctly points out that regional maintenance did not require electrification. Ex. AT-431 at 9, 20.

1329. Since 2005, the total headcount has been constant with minor fluctuations. Ex. AT-492 at 1-2 {2005 (818), 2006 (777), 2007 (803), 2008 (807), 2009 (768), 2010 (764), 2011 (789), 2012 (813 estimated)}. Further, there is a budgetary constraint by the Owners as to staffing levels at Alyeska as testified too by Johnson. Tr. 8298:19-23. The minimal number of staff reductions are not the result of electrification. As discussed above, staffing levels are based on Alyeska's staffing strategy based on regionalization of maintenance and spill response, automation, and pipeline events and are not driven by the electrification of the MLUs. Exs. At-405 at 6, 8-9; AT-431 at 21.

1330. A driver for electrification was O&M reductions. The only evidence of O&M costs is "headcount reductions." The Carriers argue that they have achieved a significant reduction in O&M costs as a result of the reduction of workers at the pump stations through automation of the pump drivers and other TAPS infrastructure. The Carriers did not provide a detailed breakdown by financial accounting of O&M costs reduced as a result of electrification or personnel costs. In addition, they did not provide any evidence of a reduction in head count since SR was completed at PSs 3, 4 and 9. Further, unmanned operations have not been achieved at the PSs that have undergone electrification. Ex. AT-431 at 13. Consequently, it is determined that they did not meet their burden of proof.

1331. Overall personnel costs are increasing. Witness Grasso testified there are no actual savings in O&M expenses or that the SR project has not produced the long-term O&M cost reductions projected. He analyzed the actual expenses for 2004-2011 as compared to those projected in the 2004 LRP. Witness Grasso concluded that O&M expenses substantially increased during this period and exceeded the projected 2004 LRP expenses. Exs. AT-435 at 9-11; AT-440. *See also* Ex. AT-405 at 17. Moreover, current 2013 projections estimate that the costs will continue at the current level through 2027.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Exs. AT-435 at 14-15 and At-443. Thus, it is concluded that the SR project did not reduce long-term O&M.[592]

1332. The Carriers argument about the year of the LRP used by Grasso is specious.[593] For instance, Carrier witness Ganz used a 2002 draft LRP. He testified he did not know which LRP the Carriers relied on in proceeding with SR. Tr. 7785:7-11. He also testified that the LRP he used was a draft version prepared on July 15, 2001. Tr. 7787:20-22. Thus, it had only six months of actual numbers as he testified. Tr. 7789:17-21. Although he did testify that it could have included only three months of actual numbers. Tr. 7790:5-6. Moreover, Ganz did not review the final LRP for 2002. Tr. 7789:2-5. He also agreed that the 2002 LRP included a procurement initiative that was projected to save almost twice as much as the SR project. Tr. 7801:6-11. He did not know if the procurement initiative or a system renewal initiative was ever undertaken. Tr. 7804:2-23. Further, he did not ascertain whether the projected throughput levels in the 2002 LRP were realized and the impact it had on O&M expenses. Tr. 7806:16-21. Additionally, Ganz testified that he was aware that 2001 had a substantial amount of non-recurring expenses. Tr. 7816:5-7817:13.

1333. Anadarko points out that in 2004, the RCA found that there were "significant non-recurring costs" in an effort to reorganize the operation of TAPS through the pipeline "Realignment." Ex. AT-489 at 14. The RCA pointed out that Tesoro identified $68 million in non-recurring costs in 2001 that should be scrutinized. *Id.* at 15. Additionally, the RCA found that the Carriers paid severance packages totaling $33 million to 151 terminated employees and 99 terminated contractors as part of "Strategic Realignment" for the year 2002. The Carriers expected to save $28.3 million a year out of this initiative. *Id.* at 17. Ganz did not know if he used the projected savings of $28.3 million in his numbers. Tr. 7818:2-11.

1334. It is found that Anadarko is correct that the use of the 2002 LRP draft version is unreliable and distorts the analysis of O&M savings. Staff argues that the appropriate baseline for measuring benefits of SR is the 2004 LRP. Consequently, Ganz' testimony is not given significant weight.[594] As Staff points out, Ganz' own chart demonstrates

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[592] Dr. Toof's testimony in this regard is not entitled to any weight. Ex. ATC-36 at 93. Dr. Toof relied entirely on Alyeska's data and could not vouch for the quality of that data. Tr. 6041:17-25; 7064:18-21. He further stated he was not a technical expert and was not able to evaluate the quality of the work or the technical saving issues. Tr. 6041:20-6042:20. He was unable to comment on the quality of the information that was used. Tr. 6067:16-23. Further, he would not testify as to the accuracy of the underlying engineering analysis. Tr. 7405:16-21.

[593] Carriers IB 204.

[594] O&M expenses dropped substantially between 2002 and 2004. However, the decrease is not attributable to SR. Rather, to non-SR initiatives such as "strategic

20140227-3052 FERC PDF (Unofficial) 02/27/2014

(Ex. ATC-960 at 6) that the projected O&M costs after 2005 actually increased and thus the shippers have not received any benefit from the SR projects with respect to O&M costs.

1335. B. Sullivan testified the Carrier's O&M expenses increased, from $357 to $358 million (this is after removing ad valorem tax, fuel and power costs). Tr. 351:6-353:8. According to B. Sullivan, fuel and power costs decreased by $15 million from 2006-2010, which means that the increase in the other elements of O&M, including staff and maintenance costs, is even larger than the overall total numbers reveal. This witness concluded that there is no net benefit to SR but the opposite since the ratepayer is paying an additional cost. Tr. 349:14-15 (second phase). According to this witness there is no net benefit to SR because the O&M has continued to go up and the Carriers spent $750 million to continue to have an increase in O&M cost. Tr. 314:14-19.[595]

1336. The Carriers claim that by the end of 2010 they had eliminated 263 out of 285 positions originally projected to be eliminated as a result of electrification and automation.[596] The total reduction figure does not reconcile with the figures quoted above of total headcount since 2005. The Carriers have not produced any evidence to resolve this conflict. Thus, they have failed their burden of proof. There is no clear evidence in this record to facilitate corroboration of the Carriers' argument. As a result, the conflict is resolved against the Carriers since they bear the burden of proof in this matter. The Carriers did not provide Alyeska's organizational chart before or after SR, the contractors and the work they performed before and after SR, and the work performed by third party vendors which replaced work performed by staff/contractors prior to SR.

1337. The Carriers rely on Howitt's testimony. Howitt relies on Ex. ATC-611. Ex. ATC-611 purports to be a staff-reduction analysis. The exhibit is undated and was prepared by an Alyeska business analyst. Ex. ATC-19 at 96. The date given to Ex. ATC-611 is June 2011. *See* Ex. J-2. The business analyst, Hoppenworth is not a witness in this proceeding. Ex. ATC-611 is an estimate of reductions due to SR. *Id.* at 1. It compares the estimated reductions to the projections in the 2004 annual plan. This exhibit shows reductions attributable to SR investments at PS 3, 4, and 9 as 106 Alyeska

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realignment" and "system renewal" which resulted in reductions in Alyeska headcount and related labor costs. Tr. 8499:14-22/ 7097-98:12-5.

[595] The Carriers claim that the increase in the costs from 2006 through 2010 (net of ad valorem taxes) was only about one percent per year, but the average annual cost increase for the oil pipeline industry over essentially the same period was more than 5 percent per year. Carriers IB 205. This assertion is irrelevant in the context of this proceeding since the valid comparison would be *vis a vis* the legacy equipment.

[596] Carriers IB 78.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

positions.[597] However, there is no evidence in this record to support this statement. On the contrary, the evidence in this record shows that even before SR, Alyeska was downsizing. *See* above. For instance, Norton an Alyeska Project Consultant, stated in 2003 upon the urging of Argonne, preliminarily, that the staff reductions are approximately 25 % of the current workforce. He estimated the job reductions as total Alyeska 223 and total contractors 149 which adds up to 372. Ex. SOA-180. He states "approximately a third" of the projected 372 staff reductions "will be eliminated anyway if SR does not proceed, due to other efficiencies." Ex. SOA-170. As Anadarko points out, the headcount has been relatively constant since 2005 with just minor fluctuations. Ex. ATC-611 does not reconcile this fact. Ex. ATC-611 lists four general trends that "offset SR efficiencies." Ex. ATC-611 at 4. For instance, hiring of new positions for "Workforce Renewal" in 2007 and 2008 and the conversion of contractors to Alyeska staff. *Id.* The exhibit states that these trends offset the SR efficiencies in all categories, but "primarily in Technical Support." *Id.* The trends indicate that after staff reductions Alyeska had to hire replacements. *Id.* at 5. Therefore, Ex. ATC-611 is unsupported and deemed not credible and as a result not entitled to any weight.[598]

1338. Moreover, Howitt's testimony concerning this issue is not given weight. He testified that he based his staff reductions on his site visits to PS 3 and 4. Tr. 6881:2-21. He also stated that PS 3 was unmanned. Ex. ATC-19 at 100:20. However, he only visited PS 3 for four to five hours one day and on the next visit he simply stood outside the fence. Tr. 6881:2-21; 6882:23-25. He also testified that he did not know how many people were living there on May 2011 when he visited the pump station. Tr. 6879:2-4. Contrary to Howitt's testimony the gate logs for PS 3 show the number of people entering, staying and leaving PS 3. Ex. SOA-707. Maintenance staff are living at the PLQ at PS 4 (Galbraith Maintenance Center). Tr. 6849:5-24. Rovers are working at PS 4 "around the clock, 24/7." Tr. 6858:18-21. There are technicians still working out of the maintenance base at PS9. Tr. 6852:18-23. Utility rovers still work at PS 3 and can stay at Galbraith or at the camp at PS 3. Tr. 6877:13-6878:7. The gate logs clearly establish that, in fact, personnel are continuously housed at PS 3 year-round under the current electrified configuration,[599] at a "fly camp" located within the pump station security fence that provides motel-like accommodations with hot meals, computer work

[597] The exhibit also lists 157 baseline contractor employment positions as having been reduced by SR (project contractor staff not included).

[598] Assuming arguendo that the Carriers proved that they indeed reduced 106 Alyeska positions and 157 contractor positions as a result of SR, it seems farfetched to spend over $700 million to eliminate 263 positions. Mathematically it does not add up.

[599] Exs. SOA-701-704.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

stations, and recreational facilities.[600] Therefore, Howitt's testimony on staff reductions and personnel at PS 3 are not supported by the record.[601]

1339. As Anadarko points out, any staff reductions are not attributed to the electrification of the pump drivers. As Hisey testified, Staff at the pump stations are a result of Alyeska's staffing strategy which is now based on regionalization of maintenance and oil spill response, automation, and pipeline events. Ex. AT-405 at 6, 8-9. This is confirmed by Privett. *Id.* at 6; Ex. AT-431 at 21. Moreover, as Hisey also testified, "[r]egionalization of maintenance and spill response and greater automation would have resulted in minor staffing reductions with or without the electrification of the MLUs." *Id.* at 9. Pivett also stated that regional maintenance was not a new concept to Alyeska. Ex. AT-431 at 9, 20. It had been used before called Pipeline Maintenance Team serving TAPS' north, central, and south regions. This was later reorganized into a line-wide maintenance team. Accordingly, it is concluded that regional maintenance did not require the electrification of the MLUs, and any savings associated with Alyeska's regional maintenance protocols are not attributable to electrification.

1340. There is no credible evidence in this record of savings from avoided major maintenance. Accordingly, the Carriers failed to meet their burden of proof on this issue. The Carriers assumed that SR would reduce major maintenance expenses because with de-manning existing infrastructure could be removed from service. This assumption was not based on reliable studies. As a matter of fact, the estimate of future reductions was based on a base-year estimate that was "factored" for future increases assuming as high as 50 percent increase every year for several years. *See* Tr. 4506:3-19 (Howitt agreeing the base period included a significant percentage of "what happened that wasn't expected in the past" calling avoided major maintenance an estimate that is "based on what you don't know instead of what you do know.") *Id.*

1341. Alyeska's major maintenance expenses have not gone down and instead have continued to rise. Comparing the base year (2003) to later years, major maintenance expenses have stayed consistent, and there has been no meaningful reduction as a result of the SR Project. Alyeska spent on major maintenance $77 million in 2003, $68 million in 2004, $70 million in 2005, $74 million in 2006, $66 million in 2007, $80 million in 2008, $75 million in 2009, and $81 million in 2010. Ex. AT-248. The Carrier witnesses testified that the major maintenance costs for 2008 and 2009 are recurring expenses in the cost of service. Tr. 4303:16-4304:5 (Grasso testifying as to what Ganz testified). Thus, a reduction is not foreseen for any time in the future.

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[600] Tr. 6705:6-9; 6877:13-6876:7; 6891:17-6892:15.

[601] *See* Tr. 6934:17-21; 6932:20-24. Howitt admitting that the response time for PSs 4 and 9 would be the same as it has always been.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1342. Moreover, as Hisey testified the major maintenance expense is not significantly influenced by MLUs. Tr. 3954-58. The drivers of this expense are major programs such as mainline integrity investigation, corrosion monitoring, above-ground pipe maintenance and repair, tank inspections, right-of-way civil maintenance, rivers and floodplains civil work, valve repairs, and a long list of VMT projects.[602] Ex. At-405 at 20; Tr. 3954-3958.[603] The legacy pumps did not drive major maintenance costs, and changing legacy MLUs out with electric MLUs did not generate significant savings. "The major maintenance savings were not realized because the estimate was based upon improperly scoped and undefined conceptual engineering for SR, so it was impossible to foresee the impact SR would have on major maintenance." *Id.*

1343. The maintenance projections (as discussed above) were made without a clear understanding of future operating and maintenance requirements. As Turnipseed testified "the design basis for the compressor turbine and the reaction turbine were 25,000 hours for a compressor turbine and 48,000 hours for a reaction turbine or power turbine, which is what we built our maintenance program upon, because a large portion of the maintenance on the turbine is actually performed when a CT or a PT is changed out. Ex. At-429 at 47. However, Alyeska has experienced "upwards of 50 percent reduction in fired hours." Ex. AT-430 at 23. Consequently, the turbines have to be changed out more often. Roberts[604] noted that Alyeska has decided to overhaul the cores in an Alyeska shop in Fairbanks instead of shipping them to England to be overhauled at the Siemens facility, as originally planned. Ex. AT-430 at 25.

1344. As conceived, SR was supposed to be a "turnkey" project. It would be based on pre-wired truckable modules built off-site, delivered to the pipeline, installed alongside existing facilities, connected as required, and put into service. In addition, the expectation was that the project would provide the documentation necessary to determine O&M requirements. As Turnipseed testified, it was his understanding that "strategic reconfiguration was a turnkey package" and the PMT's job was to "deliver hardware, install that hardware and then provide us with the documentation necessary to determine what was going to be needed to operate and maintain and repair it" and that the job still is not done. Ex. AT-429 at 8. He further testified that the engineering data sheets provided

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[602] The major maintenance is done almost exclusively by contractors and does not ever reflect a "lot of dollars associated with any benefits you could ever get from electrification." Tr. 3956:10-18.

[603] Hisey stated that "the major drivers of that category of major maintenance programs are programs, right-of-way programs, corrosion programs, tank programs, inspection programs, river draining structures. It's a lot of civil work and big piping and tank work." Tr. 3956:10-14.

[604] An engineer who joined Alyeska in 2000 and currently works in the low-flow studies group.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

by SNC for the equipment "were based on the conceptual equipment, not necessarily the equipment that was actually installed; and that the data sheets were not provided in an editable format so that they could be made current. Ex. At-429 at 12. According to Turnipseed the engineering data sheets had to be confirmed as correct because a majority of the sheets provided by SNC Lavalin did not have an engineer's signature and were not entered as data sheets. *Id.*

1345. SR did not reduce the workload for engineering and maintenance staff. As Anadarko correctly points out this can be attributed to the PMT's failure to consider Alyeska's established procedures and processes during the engineering and implementation phases of SR. This failure created confusion, rework, inefficiencies, and delays, contributing to significant cost and schedule overruns. This was aggravated by the PMT's failure to listen to the maintenance personnel, whose workload was increasing. Hiebert communicated her concerns for the SCADA system and remembers being told her input was not appreciated. Ex. AT-433 at 26.

1346. Anadarko's witness Grasso analyzed the actual expenses for 2004-2011 and concluded that there were no actual savings of personnel expense. Grasso's graph shows that personnel cost have continued to rise after SR. Ex. AT-435 at 7-9. The graph also shows that the actual expenses have substantially exceeded the projected expenses from the 2004 LRP. Ex. AT-441. Further, the Carriers did not provide any evidence of a reduction in headcount since SR was completed at PS 3, 4 and 9. Since 2005, the total headcount has been constant with minor fluctuations. Ex. AT-492 at 1-2. For instance in 2005 (818); in 2006 (777); in 2007 (803); in 2008 (807); in 2009 (768); in 2010 (764); 2011 (789) and in 2012 (813 projected).

1347. As Anadarko correctly points out, the project was executed prior to determining whether or not the conceptual engineering was feasible. The rush to implement SR prevented adequate due diligence to determine if the SR project was economic. The project went through six different program managers. Ex. SOA-275 at 140. They finally realized the project was a "train wreck" but they continued with implementation.

1348. The Carriers ignored the significant benefits of the legacy equipment at preliminary engineering and did not factor into their SR project analysis the fact that the legacy equipment could be used to heat the oil stream. The Carriers knew this since it had been a finding in the 1999 Reinvestment Strategy Study and this fact was ignored. This action was imprudent.

1349. The one-time tax benefit included in the cost/benefit analysis considered by the Carriers at sanction was not realized.[605] Since the pumps were not placed in service by

[605] "Approval will preserve a 2005 startup and will allow approximately $37M in tangible benefits, $21M were from accelerated depreciation" which required start of operations by December 31, 2005. Ex. SOA-487 at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the end of 2005 the Carriers did not realize the savings they had contemplated. The Carriers also factored $16 million in savings from avoided fire and gas upgrade costs. Ex. SOA-487 at 2 Ex. SOA-60 at 24. The Carriers had to upgrade the fire and gas protection systems in many of the 77 buildings that had been planned on leaving idle or cold. Consequently, much of the $16 million in avoided major maintenance savings were not realized.

1350. The project had significant cost and schedule overruns and the evidence in this case shows that it has created operational risks. For instance, SIPPS, a critical system, is a fail-safe protection system. Turnipseed testified that SIPP's detailed design documentation is insufficient. Ex. AT-429 at 15. In addition, Pivett testified that critical fire commands did not work after critical software updates had been downloaded and that adequate testing after changes is not done. Ex. AT-431 at 30-31. Anadarko is correct that this evidences inadequate MOC. Thus, MOC issues are still plaguing the project this late in the process. Anadarko is correct that this increases risk in complex processes or control systems like SIPPS.

1351. The evidence in this case also shows that there were technical issues on all facets of functional checkout commissioning at PS 9. Some were major such as "shutdown of mainline unit systems if a fire occurred" and "issues with emergency shutdown circuits." Ex. AT-431 at 30. Hiebert testified that SCADA issues should have been resolved before the start-up of PS 9. Ex. AT-433 at 41. Pivett stated that the fact that he was voicing concerns was the reason he was transferred from PS 9 before the commissioning process was completed. Ex. AT-431 at 4.

1352. Turnipseed who has been involved with the maintenance strategy since 2005[606] stated that there is no established current operating context for the SR equipment. Ex. AT-429 at 10. According to Turnipseed, it is not possible to write maintenance protocols without an operating context because "[i]f you can't understand the context under which something was conceived, under how its resident components are put together to a process, how that process is intended to operate and how that process is ultimately going to fail, because all processes ultimately fail, you cannot put in place a method for operating or maintaining that process." Ex. AT-429 at 4. As far back as 2007, Turnipseed was telling supervisors that progress had not been made in preparing to maintain the "post SR pipeline." Ex. AT-429 at 52. When maintenance strategies were established compulsory redesigns were necessary. According to Turnipseed as "late as 2011, we still had unresolved compulsory redesigns that are documented in the RCM tool kit." Ex. AT-429 at 32. Anadarko is correct that it is not credible to attribute significant benefits to SR.

1353. Pump station technicians currently do much of the work the "on-site" operators used to do. Turnipseed testified that there are still "boots on the ground and the eyes in

[606] Ex. AT-429 at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

the field looking at all SR and legacy equipment" to gather data that is "not gathered through an automated system like PI." Additionally he testified that PS 5 still has a control room operator on duty. Ex. AT-429 at 24. Utility operators "look at systems to preempt the alarm event or shutdown event, rather than allowing them to reach the point where they would reach alarm or shutdown." Ex. AT-429 at 23.

1354. As of the close of the record in this proceeding, the SCADA system is not complete. It is producing an excessive number of alarms. CS-360 establishes standards for alarms. Ex. AT-466. Up to July 2012[607] the long term standards for alarms were: alarm rate (5 per hour and 150 per day), no disabled alarms, and no chatting alarms. *Id.* at 66. For the week of July 29, 2012 through August 5, 2012, there were 18,000 total instances of alarms of which 6,884 were chattering alarms and 2,243 unique alarms. Ex. AT-480 at 128, 130. For that week the system weekly time in alarm was 19.76 hours. *Id.* at 132. It is concluded that the SCADA system is substandard and does not meet previously established standards for alarms.

1355. The Carriers argue that there were no industry standards for alarms. Carriers RB 106. However, CS-360 an Alarm Systems Standard, clearly states that it incorporated recommended practices from ISA 18.02 "Management of Alarm Systems for the Process Industry" and it also incorporated recommended practices from API 1167 "Pipeline Alarm Management." This document is dated February 18, 2010. Ex. AT-466 at 2. ISA is the Instrumentation, Systems and Automation Society. *Id.* at 14. The references cites to EEMUA or the Engineering Equipment and Material Users Association and the Department of Defense Design Criteria Standard, Human Engineering. API is the American Petroleum Institute. The first issuance of this document was in July 27, 2007. *Id.* at 2. The document establishes interim targets for systems undergoing an alarm improvement effort such as "target average process alarm rate of 300 per day vs. long-term targets such as 5 per hour (~ 150 per day). *Id.* at 66. Inhibited, Disabled or otherwise suppressed alarms are zero in either the improvement effort or the long-term target (the exception is a defined shelving, flood suppression or state-based strategy). *Id.* Alarm floods (10 to 20 alarms in a 10 minute period) are five per day in the improvement effort or 3 per day as the long-term target. Flood alarms (more than 20 alarms in a 10 minute period) for the improvement effort are 3 per day the long-term goal is 0. This document was established within five months of the first flow of oil through PS9.

1356. CS-360 also provides that the documentation and rationalization (D&R) method is used for the selection and configuration of new alarms prior to implementation. It is a

[607] On July 2012, the long-term targets were removed. Tr. 7638:9-13. The Carriers argue that these targets were removed to avoid unintended consequences such as alarm suppression. Carriers RB 106 n. 136. However, note that their long-term goals was 0 suppressed, inhibited or disabled alarms. Ex. AT-466 at 66. The inference being that they eliminated these standards because they could not comply with them.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

best practice for proper rationalization. Rationalization in the system includes the following areas: SCADA, Operations Engineering, Operations Control Center, and Maintenance. Ex. AT-466 at 18. Hiebert reported on July 2012, that the D&R process was incomplete. Ex. AT-465 at 2. She reported that at a minimum 18,813 alarm points had not been through D&R and there was "no information from initial analysis." *Id.* It is concluded that Anadarko is correct that as of July 2012 the SCADA system did not meet the standards for the D&R alarms and thus the system is suboptimal.

1357. This record does not demonstrate whether a spare parts strategy has been completed. Turnipseed stated that he has concerns that Alyeska has not identified all the spare parts, may not have identified sufficient quantities or stocking locations, and that some of these parts may be obsolete. Ex. AT-491 at 2. Turnipseed's team was responsible for identifying the spare parts needed, and engineering had to determine the quantity of those parts to be "put on hand." Ex. AT-491 at 3. This issue was originally identified in a May 2007 audit which reported the lack of evidence of a specific SR spare parts strategy, that only 478 line spare items out of 2,700 had been stocked, that $970,000 had been credited to AFE S020 for the return of spares and it was unclear which spares had been returned, and it was unclear if spare parts were being identified for several SR related projects. Ex. AT-507 at 1-2. Turnipseed also testified that the "discontent being voiced among all of us who were on the receiving end of strategic reconfiguration was universal. We were all struggling to maintain the integrity of the pipeline, and we felt as though we weren't being heard." Ex. AT-429 at 27.

1358. Anadarko argues that even if PS 1 is completed on schedule and under budget, SR is a failure. Additionally, it contends that SR has added useless complexity to a system that was operating reliably for over 30 years. According to Anadarko if the Carriers had appropriately studied the project they would have realized that the savings were not attainable and costs were underestimated. Given more time the scope would have been properly defined and projected costs and savings would have been realistic. Anadarko is correct.

1359. Tudor and Yaegge's testimony concerning the SR project do not support the Carriers' contentions that they acted prudently. As a matter of fact, Tudor's testimony lacked candor in significant respects. Tr. 4972:3-4. They could not explain why the costs escalated, and Yaegge who had initially questioned the numbers could not explain why the cost escalated and how she was told about the original numbers. Tr. 4765:1-4. On the other hand, Flood admitted that hybrid "was an assumed case that was set up for purposes of evaluation. The hybrid case was never a case that we were prepared to execute." Tr. 5315:10-12. He further testified that the real consideration was do we make an investment or do nothing. *Id.* at 15-16. Flood also confirmed that Conoco did not independently confirm that the SR Team had the proper scope for the project. Tr. 5308:23-5309:11. Moreover, the original decision maker from BP (BP was and is the majority vote on the project) did not testify. Further, J. DeHaas who has numerous emails in the documentary evidence was not presented as a witness in this proceeding.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

The fact that Anadarko and the State waived cross examination of some witnesses does not inure to the Carriers benefit as proof that their claims are correct. On the contrary the fact that for some witnesses cross examination was waved is due to administrative efficiency and the fact that the record had ample development.

1360. Barrett also testified that the Carriers knew or should have known the various problems that led to cost escalation of the project. Tr. 5797-5850. Pomeroy and Johnson also testified that the SR Team did not do any meaningful benchmarking of the SR project and were not aware of anywhere in the world where a pipeline had converted from gas-powered pump drivers to electric powered pump drivers or of any pipeline in the "Lower 48" that operates electric pumps when it is remote and off the grid. Tr. 8023:3-4; 8024:20-24; 8024:25-8025:3; 8066:19-22; 8251:9-12; 8253:18-22.

1361. There is no dispute in this record that the Carriers undertook the project to reduce operating costs.[608] SR was not required for reliability[609] nor was it a lifecycle replacement.[610] Moreover, as Anadarko points out, SR did not add new capacity, new markets or new supplies. Anadarko is correct that a project such as this required extreme high accuracy on cost projections, and this in turn required properly defining the scope of the project. Even the Carriers witnesses admitted that there is a direct correlation between the amount of uncertainty in a project and the level of project definition. Tr. 5798:2-11 (Barrett). Yaege testified that you "do have to get your scope right to get your cost estimates right." Tr. 4764:15-18.[611]

1362. In their initial brief the Carriers argue that the project was prudent and what happened was that "not … everything went as planned." Carriers IB 6-7. However, Anadarko is correct that the delays and cost overruns in this project were more than minor deviations from the plan. For instance, the Carriers' mistaken assumption concerning the amount of "brownfield" work required by SR, [612] was a major driver of the cost increases experienced by the project.[613] This was a significant mistake that has

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[608] *See, e.g.*, Tr. 4604:8-12; Tr. 4779:16-17 and Ex. ATC-18 at 12.

[609] Ex. AT-218 at 11.

[610] Tr. 7985:11-23.

[611] Ex. SOA-171 at 2 ("The TAPS Owners sanctioned a $200M+, project, before starting design engineering . . . Design engineering was finished in May 2006 (approx.); this is a prerequisite for a valid cost estimate").

[612] Carriers IB 7 and 145 n.61.

[613] Tr. 3590:19-3591:21; Tr. 3926:1-3928:8; Ex. SOA-213; Ex. SOA-383; Ex. SOA-324 and Ex. SOA-453.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

no reasonable explanation on this record short of imprudence. The SR Team knew that the SR project was unique and they were not aware of any other pipeline that had replaced gas turbines to electric drives on an existing pipeline.[614] Additionally, a number of previous significantly detailed studies were ignored.

1363. The Carriers claim that even with the cost growth the project provides shippers and the State with net benefits that justified the additional costs. There is no evidence in this record to support this statement. SR has not been completed as of the writing of this decision, there are no savings from the project and the costs tripled. The Carriers sanctioned the project in March 2004 with an estimated cost of $252 million. Ex. SOA-55. In 2005, the costs had skyrocketed and the Carriers were very aware that a supplemental AFE for $434.5mm had slightly less than a 59% probability of being achieved. Ex. SOA-345 at 7. However, the Carriers decided to continue with the project. As of March 2011, the cost of SR is $707.8 million and the project is still not complete. The new projection is that it will require an additional $77.9 million to complete PS 1, so the total cost of the project will be $786 million. Not included in this are the cost incurred by Alyeska to implement the project since it took over in 2005. Anadarko is correct that the true cost of the project will never be known. Grasso compared the 2004 LRP projected costs with actual costs. Ex. AT-435 at 11-12. He also graphically depicted project cost growth. Ex. AT-441. He also added 10% to Alyeska's baseline personnel costs for 2004-2009 to account for what Hisey believed was a minimum estimate of the amount of time, on average Alyeska employees[615] were in some way involved with SR implementation. Ex. AT-405 at 24. The actual costs overrun is substantially more than anticipated.

1364. The Carriers argue that if SR had not taken place the legacy equipment would have needed modifications of approximately $150 million per pump station. Carriers IB 117 n.45. This was a rough order of magnitude (ROM) estimate done in April 2011 because the Carriers "are involved in a pipeline tariff case." Ex. ATC-610 at 3. Howitt confirmed that this report was done specifically for this case. Tr. 4363:18-20. The study did not determine if the equipment needed to be replaced. Tr. 4365:5-8. The report assumed everything associated with the pumps and drivers would be replaced. Tr. 4368:13-17. The report included the replacement of three mainline units. Howitt confirmed that since 2000, Alyeska had determined it would only need two Avons in 2010. Tr. 4367:7-10; 4367:24-4368:2. The cost of the equipment was estimated to be $21.14[616] million per pump station and included an escalation multiplier of $99.36 million ($120.50million - 21.14 million) for installation in a brownfield environment.

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[614] Tr. 8031:17-21; Tr. 8066:19-22; Tr. 8251:9-12; Tr. 8253:18-22.

[615] The figure does not include cost associated with some of the SR-related projects that were worked under Alyeska baseline budgets. Tr. 3984:15-3985:23.

[616] Ex. ATC-610 at 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Ex. ATC-610 at 6; Tr. 4368:24-4369:4. It also included $18.5 million (approximate) to replace and reroute piping including a $5.7 million contingency (50%) and a $1.1 million escalation (10%). Ex. ATC-610 at 35. These costs were to replace piping that had not been replaced as part of SR and still needed to be replaced. Tr. 4377:6-10. These costs should not have been included in this report since it entails costs that had to be made regardless of SR. This report done while in litigation is not given any weight. This report does not show what a reasonable utility manager would have done in good faith, under the same circumstances, and at the relevant point in time. They cannot prove what it would have cost to replace the legacy equipment circa 2002 with a 2011 document.

1365. The Carriers also assert that if they had done Hybrid, they would now have to begin to reconfigure the pump stations at an additional cost, since the legacy equipment would have to be replaced to maintain system reliability. Carriers IB 116-17. There is no factual support for this statement. Additionally, in a 2009 study it was concluded that the legacy equipment was still operating reliably and this same study indicated that the "option [to maintain the legacy pumping equipment] initially appeared promising in meeting the [SR] project's budget constraint." Ex. SOA-574 at 4. Further the Carriers' claims are contradicted by the fact that the legacy equipment continues to function reliably at PS1 today.

1366. The Carriers cite to AFE S420 for support (PS 4 completion). Ex. ATC-384 at 8-9. This is a 2008 document seeking funding to complete construction of PS 4. Therefore, this document again cannot show what a reasonable utility manager would have done in good faith, under the same circumstances and at the relevant point in time. Moreover, on its face the document is not supported by the evidence in this case. The Carriers' statement that spare parts for the legacy equipment were hard to find is also not supported by the evidence in this case. The evidence in this case shows that at the time of sanction, there was a large inventory of spare parts since a number of pump stations had been decommissioned. Ex. SOA-429 at 15, 24. The decommissioned equipment could also replace legacy equipment if the need arose. Ex. SOA-19 at 2.

1367. Hisey confirmed that if the Carriers had automated the legacy equipment, Alyeska would have had a large supply of spare parts since a number of stations had been ramped-down. Tr. 4000:10-16. Moreover, Rolls-Royce, the Avon manufacturer has as a goal "ensuring our spare parts are not rare parts." Ex. SOA-595 at 2. Rolls-Royce also states that "our dedicated component supply teams ensure that you are never left wanting for the original equipment spare part that you require." Ex. SOA-595 at 2. Pomeroy testified that any issues with spare parts related to the control systems and not the legacy MLUs. Tr. 8080:5-22. The State posits that if the Carriers had done even a cursory search of the internet, they would have found that there are several companies that are ready, willing, and able to provide spare parts for the legacy equipment. Exs. SOA-595 (Rolls-Royce); SOA-596 (Rolls Wood Group); SOA-597 (TransCanada); *see also* Tr. 5599:2-24. Anadarko and the State are correct, that a lack of spare parts was not a justification for replacing the legacy equipment.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1368. The Carriers also claim that the legacy equipment could not "function at the lower through-put levels that are now forecast" citing the testimony of their witness Orieux. Carriers IB 118. As shown above, the legacy equipment could be modified to handle low-flow conditions. Orieux did not perform any studies or provide any factual support for his statements. Ex. ATC-32 at 13. He had limited turbine expertise and he lacked experience with Avon turbines. *Id.* at 1-2; ATC-39. Thus, his testimony in this regard is not entitled to any weight. Moreover, BP's throughput forecasts indicate that the legacy equipment would not have needed to be replaced. Ex. SOA-554; *see also* Ex. SOA-542 at 24:3-8.

1369. As the State and Anadarko point out, the electrification equipment is overpowered for current flow rates, and the Carriers discussed options to address this matter in the 2009 Pump Station 1 Scoping Study (install artificial load banks to absorb excess electricity generated by the equipment, or [r]ecycle crude oil within the pump station to raise power requirements)." Ex. SOA-574 at 16. This study also notes that the new electric turbines cannot be turned down below 60% due to air quality permit issues. *Id.* at 4, 16. The Carriers knew this starting in July 2004. Ex. SOA-288 at 9. Accordingly, it is found that the Carriers cannot justify electrification as a lifecycle replacement project, especially since the new turbines are overpowered and the Carriers have discussed the need to add artificial load banks or recirculation to remedy this problem.

1370. The Carriers also mischaracterize the evidence in this case. In a footnote in their IB the Carriers assert that Alyeska operating procedures establish the minimum operating speed for the Avon turbines at 6400 rpm. Carriers IB 120 n.49. Howitt a Carrier witness testified "[d]uring normal cold weather in January and February this past winter (-30 to -50 degrees F), the gas turbines at Pump Station 1 operated at or below 6100 rpm for an extended period, which is below the *previously* defined minimum operating speed of 6400 rpm for the machine." Ex. ATC-917 at 36:3-6 (emphasis added). Howitt accurately stated that 6400 rpm was the "previously defined" minimum operating speed because the limit was removed by Alyeska in November 2009. Ex. SOA-677. DeHass stated in an email dated November 17, 2009 that the "previous 6400 Rpm stipulation may have been a bit too strongly interpreted. We have always allowed normal operation below 6400 Rpm." *Id.* The Carriers' turbine expert, J. Scott did not express an opinion on the ability of the Avon turbines to handle the declining flows projected in 2003. Tr. 5625:5-21; 5627:1-5.

1371. Further, the Carriers also argue that SR improved the MLUs. Carriers IB 78-9. The evidence in this case shows that the electric MLUs are more complex than the direct-drive fuel MLUs and require far greater maintenance. Pomeroy stated that he was not surprised to see that the SR VFDs require the largest amount of preventive maintenance hours. Tr. 8083:8-8084:2. In addition, the electric MLUs are less able to adjust to the entire range of potential future throughput levels than the direct-drive fuel turbine MLUs.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Ex. SOA-574 at 19.[617] At the current throughput levels, the SR configuration requires five electric MLUs to obtain positive flow, only two direct-drive fuel turbine MLUs would otherwise be required. *See* Ex. AT-490. Further, to date, every core of the new SR electric turbine generators has had to be replaced. Tr. 6815:14-17. The core of the turbine generators needs to be changed out every 14-15 months. Tr. 7051:5-14. Alyeska has to rebuild the SR turbine generators within Alaska because it is unable to get them rebuilt in a reasonable timeframe from their manufacturer. Ex. SOA-692 at 6-7. Additionally, the SR turbine generators are improperly sized for current throughput levels and have to operate well over the necessary load to operate efficiently enough not to violate air quality control standards. Tr. 8483-8484 (Carriers' witness Johnson stated the Siemens generators have to be operated above 60 percent load in order to satisfy the air quality permit). The white paper for PS 1 states that the direct-drive fuel MLUs may be best suited to its continuing operation and that the SR turbine generators are not even the best electrification option. Ex. SOA-574 at 6 and 10.

1372. Anadarko argues that the current control system configuration is suboptimal. The Carriers have had to provide redundant equipment for operations and control systems to operate both the legacy and the electric equipment. Ex. SOA-425 at 41. The control systems were designed differently from a system operating new equipment on a new pipeline. Tr. 3566:7-18. In addition, all four pump stations are configured in different ways while the system is transitioned to an automated system. Ex. AT-263 at 3.

1373. The PSs are not unmanned.[618] PS 3 was supposed to have been completely unmanned under SR. Both Turnipseed[619] and Privitt confirmed that the PSs are not unmanned. Ex. AT-429 at 22; Ex. AT-431 at 13-19. PS 3 is manned and keeps people there virtually all the time. PS 9 is manned, during the day, it has a full maintenance crew and a full-time baseline crew on staff. PS 4 is a fully manned facility, so it has

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[617] Table 1- Power Load Strategy at PS1, at throughputs less than 600,000 bpd PS 1 requires 7 MW or less of power, the Siemens Cyclone handles 0 percent of the load.

[618] Originally the pump stations were designed to be unmanned. However, shortly after initial startup PS 8 had an explosion and "people were deployed in the field to ensure reliability and they have been there ever since. Ex. SOA-572 at 13 n. 22. To ensure reliability, redundancies were put in place including personnel in the field, over $100 million in excess equipment, multiple back-up systems, and the Alyeska engineering organization. *Id*. at 13. Many of these redundancies have been eliminated as a result of SR in an effort to cut costs.

[619] Turnipseed also testified that at PS 7 "in the winter, when crude oil temperatures are lower, they are now bringing in a crew of retired technicians on contract, or technicians from PS 5 to provide 24-hour-a-day support at any time the … there's a potential for the oil temperature to drop below 40 degrees in the pipeline." Ex. AT-429 at 23.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

essentially 24-hour call-out for immediate response within a matter of minutes, and it has a full maintenance crew and it has a full baseline crew. Ex. AT-429 at 23. There is still considerable support for the equipment and related facilities after SR. Ex. ATC-917 at 25.

1374. In May 2010, while running fire-system tests the main power supply was cut, a breaker tripped open and prevented the backup power from kicking in. The power failure caused valves on a large oil storage tank to open and oil began filling the tank. Workers in Anchorage and Delta Junction focused on restoring power and did not notice that the tank was filing. The tank overtopped, spilling oil, and creating an explosive hazard that required the pipeline to be shut down for three days. Alyeska was unable to determine why the breaker tripped and had to redesign the backup power at the pump stations. Ex. AT-263 at 2. Staff noticed the spill and were able to report it by radio to the OCC, the OCC had lost visibility to and control of the pump station. Ex. AT-262 at 7-8. There have been prior events of a similar nature. *Id*. at 9. At the time of the May 2010 incident, one individual filled three roles, including pump station caretaker, maintenance technician and chief contact person for one of the tests scheduled during the shutdown. Ex. AT-263 at 3. Since the spill, federal regulators have required Alyeska to keep additional workers at the pump station around the clock, inspecting for leaks or other problems. Ex. AT-263. As a result, PS 9 is not currently unmanned. Consequently, the Carriers have not proved that de-manning the stations was a benefit of SR.

1375. SR eliminated waste heat from the legacy equipment that could have been used to heat the oil in low-flow occasions.[620] Now the Strategic Plan for 2010-2033 indicates that the cost of installing equipment to add heat to solve oil cooling problems as a result of low-flow conditions ranges from $500 million to as high as $2 billion. Ex. SOA-148 at 3; *see also* Ex. SOA-1 at 66, 72; Tr. 1789:14-22 and 3719:2-9.

1376. Finally, the SR project is not complete. PS 1 is operated with legacy equipment. In 2006, PS 1 implementation was stopped and it was restarted recently (now called Electrification and Automation or EA). The work is expected to be completed by 2014 at $84.069 million. Ex. AT-421 at 16. A 2009 study found that the installation of the Siemens TG at PS 1 would provide "relatively low financial savings potential in terms of installed equipment" and "[would pose] long-term flexibility/scalability challenges

[620] Prior to eliminating the legacy equipment, it generated substantial amounts of waste heat that could have been used to ameliorate any oil cooling problem. Tr. 3720:8-17. This possibility was discussed in the January 18, 1999, Reinvestment Strategy Study. Ex. ATC-105 at 11. The Carriers recently reactivated the legacy pumps and equipment at PS7 for the sole purpose of adding heat to the oil stream. Ex. AT-270; Tr. 5643:9-5644:3. Therefore, the Carriers overlooked the advantages of using the legacy pumps to add heat to the oil stream before sanctioning SR. Tr. 3720:8-18. This is not the behavior of a rational utility manager.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

related to operating the 12.9 MW Siemens TG as declining throughput rates cause air quality emissions to approach low load operational thresholds." Ex. SOA-574 at 7. The study also concluded that the payback period for this option was "never" and the IRR was "negative." *Id.* at 26-29. Again this shows that these costs are not the type of costs that a rational utility manager would incur.

1377. As Anadarko argues, the evidence in this case clearly demonstrates there was no reliability or other service-related need to replace the legacy equipment on TAPS. Therefore, it must be concluded that the replacement of well-functioning equipment that is near-fully depreciated with new equipment recapitalizes the rate base, thus artificially inflating rates. Ratepayers receive the same transportation service they received before SR, but must now pay for unreliable new equipment when the legacy equipment had decades of remaining useful life and would otherwise continue to provide more reliable service than seems possible with the new equipment. The PS 1 White Paper demonstrates that all options considered for replacement of the legacy equipment have "negative" internal rate of returns, negative net present values, and a payback period of "never." Ex. SOA-574 at 25-29. However, keeping the legacy equipment was removed from consideration when Property Accounting advised the project team that if the equipment currently installed at PS 1 was not placed into service for transporting crude oil, the owners would be required to expense up to $91 MM and none of the write-off would be allowed in the Tariff rate. Ex. SOA-574 at 5. Thus, the Carriers are moving forward with the electrification of PS 1 even though, at current throughput projections (around 550,000 bpd), there will be 0 percent load placed on the 12.9 MW Siemens Cyclone turbine. Anadarko argues that the Commission should not encourage the installation of unneeded upgrades at ratepayer expense. This is correct.

iii. *Disallowance*

1378. The State argues that the Carriers have not met the burden to establish that their rates are just and reasonable[621] including that the costs of SR were prudently incurred.[622] SOA IB 211. As established above (Burden of Proof) the state and Anadarko shifted the burden both substantively and procedurally to the Carriers to establish that the costs of SR were prudently incurred.[623] Anadarko is correct that the Carriers failed to support the prudence and reasonableness of the specific SR costs and failed to provide key evidence regarding the project and the decision making process. For instance, the Carriers did not present key BP decision makers even though BP is the biggest Owner on TAPS. Moreover, this record clamored for the testimony of J. DeHaas the top rotating equipment

[621] *Anaheim et al. v. FERC*, 669 F.2d at 809.

[622] *Minnesota Power & Light Co.*, 11 FERC ¶ 61,312 (1980).

[623] *Cleveland Elec*., 19 FERC ¶ 65,088 (once the burden shifts the Carriers had to dispel all doubts and prove the costs were the result of prudent management).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

engineer. Yet he was not produced as a witness by the Carriers. The inference drawn is that these witness were not produced since their testimony was not favorable to the Carriers.

1379. Additionally, as concluded above, the Carriers imprudently sanctioned and managed the SR project. A regulated entity is entitled to recover its costs from consumers if it acted 'prudently' in incurring those cost, or it may not recover costs which were imprudently incurred. *Violet*, 800 F.2d 282 (citing *Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission*, 262 U.S. 276, 289 n. 1 (1923)).

1380. As of the close of the evidentiary record in this proceeding the Carriers have spent $707.8 million in Electrification. This includes $132.6 million on PS 1 as of March 2011.[624] The findings and conclusions above include the finding that PS1 was part of the imprudent actions, since it was part of the SR project *ab initio.* Moreover, in 2009 they decided to continue with electrification of PS 1 not for technical reasons but so as not to loose $91 million in expenses that would not flow through rates if the equipment was not put into service. Therefore, the finding of imprudence includes the costs for PS 1 up to the year 2009 or $132.6 million (when the Carriers try to flow these amounts through the rates a determination will have to be made as to the prudence in execution of PS1 starting from 2009 forward). However, Anadarko argues that the costs at issue in this case are a very conservative estimate that does not include all of the SR costs that have been placed in rates. Anadarko states that the costs in this case do not include (1) SR costs that were included as part of Alyeska's "baseline budget;"[625] (2) costs of several projects that were necessary parts of or closely related to SR, but were funded through other AFEs;[626] (3) a variety of SR-related costs that were expensed by Alyeska, rather than capitalized;[627] and (4) charges against prior ratepayer contributions to the Carrier for dismantlement, removal and restoration (DR&R) for SR-related removal of various structures and equipment.[628] Ex. AT-493 shows that AFE SO20, which underlies the disallowance theories in this case, is only one of many AFEs related to SR. Thus, there is a universe of SR costs that are being recovered in rates.

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[624] Exs. SOA-582; SOA-578; *see also* Ex. SOA-546 at 20-21.

[625] Tr. 3541:8-3542:16 (portions of SR work were transferred to Alyeska's operations department and paid from baseline O&M budgets). *See also* Tr.3575:17-3576:25; 3577:1-3581:15; 8002:2-12; 8264:12-19 and Ex. AT-235 at 4.

[626] Tr. 1989:14-1991:5; 3980:5-3981:2; 4536:7-4537:13 and Ex. AT-493 at 2.

[627] Ex. AT-18 at 137-40; Tr. 4537:14-4539:6.

[628] *See, e.g.*, Ex. ATC-108 at 20-31.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1381. Discounting the $132 million for PS 1, what has been spent on SR is approximately $575.1 million. Although the State argues that the Carriers have not proved the prudence of any of their costs, it seeks to disallow the difference between what electrification cost *vis a vis* a prudently executed hybrid option. SOA IB 212. According to the State, under hybrid the Carriers would have spent $199.8 million with the same benefits (excluding PS 1). The State's remedy seeks to disallow $375.3 million or the difference between $575.1 minus $199.8.[629] It argues its experts estimated the cost of Hybrid based upon the Carriers' own seven years of engineering studies. Additionally, the State claims that the Carriers did not offer a credible alternative estimate of the cost of Hybrid. According to the State, the failure of the Carriers to prove any mitigating credit means that the cost of Electrification should be disallowed in its entirety.

1382. Further the State maintains that their figures for the cost of Hybrid are supported by the evidence. SOA IB 213. It started with the Carriers $162.9 million Hybrid estimate and added $46 million for escalation costs identified by BP and $9.7 million for costs for implementing the regionalized Oil Spill Contingency Plan.[630] Additionally, the State added $18.5 million to account for SIPPS (excluding PS 1).[631] Further, the State subtracted PS 1 costs of $37.3 million. The State argues that the costs for Hybrid were well developed beyond the conceptual engineering due to the studies conducted from 1994-2001. This was corroborated by the testimony of B. Howitt. Tr. 4588:12-24 and 4588-4590. Earlier studies were in the ballpark figures with $67 million for control systems (validated by Kenonics) and $86 million for maintenance. SOA IB 215. State witness D. Sanders testified that turbines are automated and operated from remote locations all over the world. Tr. 1093:23-25; *see also* Ex. SOA-543 at 44:13-15 (Dr. Boyce concluding that control systems on the legacy equipment could have been upgraded to provide for complete remote operation). Likewise, the $86 million maintenance estimate had a high degree of reliability since it was based on 20 years of operating the legacy equipment, a totally brownfield project which had already undergone one control system upgrade. SOA IB 216, Ex. SOA-162 at tab (e); SOA 18 at 8; SOA-316 at 2. Moreover, Hybrid involved modifying existing equipment unlike electrification which required assumptions on how new equipment and infrastructure

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[629] Ex. SOA-546 at 1-3. State's IB 212-13.

[630] Ex. SOA-545 at 4:20-23; *see also* Ex. ATC-910 at 12:15-16.

[631] *See* Exs. ATC-243 at tab "Hybrid All" cells Y52 (expense) and Y74 (capital); SOA-11 at 16; SOA-582 and SOA-578 at tab "Cost by Loc". State IB 213-14 ("the State increased the amount set forth in the Reply Testimonies of Adams and Dr. Horst to complete Hybrid by $18.5 million. . . to account for the costs associated with completing the Safety Integrity Pressure Protection System ("SIPPS") project, excluding PS No. 1 costs.").

20140227-3052 FERC PDF (Unofficial) 02/27/2014

would be integrated to the pipeline (these assumptions for electrification proved to be wrong). Ex. SOA-316 at 2. The State further contends that the Hybrid estimates may have been too high since they were based on 2001 technology which could have changed by the time of sanction allowing cheaper costs and more maintenance and staff savings.[632]

1383. Next, the State argues that the escalation figure is reasonable and based on the Carriers' own analyses. SOA IB 217. In August 2005, BP estimated costs were understated based on its observations of actual costs. Ex. SOA-11 at 16-18. Thus, revised economics increased the Inertia Case by $46 million phased over the life of TAPS.[633] *Id.* at 18. The State concluded that similar cost escalation would take place with Hybrid. Ex. SOA-546 at 11-12. However, the State claims that Inertia had more major maintenance than Hybrid and using the same escalation for Hybrid may have resulted in Hybrid costs being overstated.[634] Additionally, the Hybrid estimate included a 20% contingency ($31.8 million) at the time of sanction,[635] thus the escalation factor may overstate the hybrid costs. The State added the $31.8 million to the $46 million escalation estimate for a total of $77.8 million to account for unknown cost increases. The State disfavors the Carriers argument that Hybrid should have the same escalation as the poorly managed Electrification project.[636] Assuming that Hybrid costs would be

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[632] The State argues that the Carriers did not introduce any evidence in support of their suggestion that the 2003, $162.9 million estimate did not include major maintenance costs and only included new investment costs. Carriers IB 225 n.122. The 2003 estimate does not provide any explanation of the specific cost estimates, and no other evidence is offered to support the Carriers' claims. The State notes that funding for hybrid had already been curtailed by October 2002 to December 2003. However, the Carriers allegations are contradicted by the fact that Alyeska's earliest presentations of the Hybrid option included major maintenance costs in the estimates. Ex. ATC-158 at 8. Thus, the record does not support the Carriers arguments concerning the 2003 estimates.

[633] The Carriers in reply argue about the use of the $46 million. They argue that the $46 million is "related to an increase in the expected cost savings to be realized from electrification." Carriers RB 134. However, the use of the $46 million is congruent with the evidence since BP re-based the no-electrification case by phasing $46 million (gross) of higher operating costs over the life of TAPS. Ex. SOA-11 at 18.

[634] Ex. SOA-162; see also Ex. SOA-275 at 154-55 (The State's economic analysis assumes the full $46 million is spent during the first few years of the project rather than spreading the costs out over TAPS remaining life. If the costs had been spread over TAPS remaining life, the economic analysis for Hybrid would have been better.

[635] Exs. ATC-243 at tab "Hybrid-All" cell Y72; SOA-60 at 3.

[636] *See* Ex. ATC-36 at 72:14-18.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

escalated as Electrification, is an invalid assumption, according to the state. The Carriers cannot assume that hybrid would have been as poorly managed, the State argues. According to the State, hybrid was essentially a lifecycle upgrade project with limited modification of existing equipment and facilities in conjunction with normal major maintenance cycles. Moreover, the modifications were to equipment well known to Alyeska personnel.

1384. The State also argues that the costs of Hybrid should not be inflated by the same cost escalation factor as with the imprudent Electrification since Hybrid did not involve the complexities of electrification.[637] For instance, building and installing new pump station modules on new foundations, massive amounts of new cable and cable trays, piping and electrical tie-ins and the installation of entirely new and unproven pumping equipment. According to the State, these were the areas where the Electrification costs estimates were particularly erroneous. Tr. 3279:20-23; Ex. SOA-21. Dr. Toof's testimony in this regard is not credible.[638] First, he had no studies to back this statement. Second, he testified he relied on Alyeska's assessment of the cost growth of Hybrid. There is no such assessment on this record. Third, he questioned whether the Hybrid project could have been "any more properly managed." Tr. 6077:10-14.

1385. The State argues that unlike electrification hybrid was always primarily a brownfield project premised on adding significant levels of automation to the existing legacy pumps. This premise did not change from the time it was initially studied in 1994 through the time BP informed the Owners that it did not support spending any more money on it. Thus, the State argues the engineering assumptions for hybrid were never as flawed as for electrification (assumed Greenfield). As a result, the cost estimates prepared by Alyeska and validated by Kenonics properly accounted for the increased risks associated with working in a brownfield environment. The personnel working on the estimate knew that hybrid was primarily a brownfield project. Tr. 5486:9-12. Thus, it is found that the Carries do not have any evidence to support their Hybrid cost growth claims. The more credible growth is the States' $46 million cost escalation figure.

1386. Next, the State argues that it was reasonable to add $9.7 million for the OSCP and $18.5 million for SIPPS. Conservatively, the figures come right out of the spent figures minus PS 1. Ex. SOA-582; 578 at tab "Cost by Loc." This is found reasonable since it is money actually spent on these projects. Consequently, it is found that the State's methodology is reasonable. The State is correct that the Carriers do not have specific criticisms of the State's analysis. They generally oppose it, but no concrete evidence has been offered by them. Moreover, the Carriers have not provided any credible alternatives.

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[637] Carriers IB 122-27.

[638] Dr. Toof testified that Hybrid would have experienced at least the same cost growth as electrification. Tr. 6074:15-21.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1387. Further, the State is correct that the Rough Oder of Magnitude 2011 report created by Stantec[639] for this litigation overstates the work for the Hybrid option and overstates the costs. For example, the Stantec Report estimates the replacement of every single pump and turbine at every pump station. However, it did not study the condition of the existing equipment. It essentially, ignores the fact that the legacy equipment was functioning well and could be maintained indefinitely. Ex. SOA-24. As Sanders testified a reasonable manager would not replace existing, well functioning equipment with brand-new equipment and fail to use existing equipment or infrastructure. Ex. SOA-542 at 74-75. It contradicts the 2009 scoping study that found that retention and automation of the legacy turbines at PS 1 could satisfy the operational needs of the pipeline. Ex. SOA-574. Further, concerning the replacement of all MLUs, Sanders testified that a reasonable manager would explore re-conditioned MLUs from warehouse stock. Ex. SOA-542 at 74-75. J. DeHaas stated that Alyeska had ample supply of used equipment. Ex. SOA 21. The Stantec report includes work that was never considered in the Hybrid studies and assumes three MLUs at each pump station. However, the evidence in this case indicates only one MLU and one backup would be required to operate the pipeline. Ex. ATC-610 at 3. The Stantec Report does not compare to the years of study of the Hybrid option and is on its face a ROM cost estimate,[640] based on budgetary pricing from vendors.[641] The State is correct that this report is not a credible alternative to the Hybrid option and this report will not be given significant weight. It is found that the fact that it was done in contemplation of litigation further diminishes its credibility.

1388. The Carriers claim that the State failed to "give appropriate credit for the avoided major maintenance and personnel reductions on which the SR project was premised . . . ." Carriers IB 218. According to the State, the Carriers claim that "[t]he two principal categories of benefits made possible by the SR project are reduced O&M expenses (mostly from reduced staffing) and avoided major maintenance expenses." *Id.* at 220. The Carriers aver that hybrid would not have allowed the same type of savings, yet they do not identify any specifics or provide any credible evidence to back up their broad claims. The State also argues that the Carriers have failed to prove that Electrification would save personnel costs over Hybrid. The detailed studies of the legacy equipment showed that Hybrid would allow staff savings and probably if it had been studied beyond 2001 the staff savings would have been greater due to technological advances, according to the State. The person who put together the staffing estimates for the 2002 decision document and AFE S020 never even read the reports done on Hybrid. Johnson's Hybrid numbers are unsupported and contrary to the record evidence in this proceeding or AFE

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[639] Ex. ATC-610.

[640] Ex. SOA-542 at 76:6-9.

[641] The estimate was not based on economic alternatives, one contractor was told if there was a difference to use the higher cost option. Ex. ATC-610 at 31.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

180. Johnson projected hybrid staff savings of 140 while AFE 180 projected 265. *Compare* Exs. SOA-161 at 21 and SOA-153 at 11. The higher personnel reductions for Hybrid in the Strategic Initiatives Report and AFE F180 were based on Bailey. Ex. SOA-153 at 18. Bailey was created by subject matter experts[642] and Alyeska, and the projections were validated by the Fairbanks Business Unit Conceptual Engineering group.[643] Contrary to the Carriers' arguments this is what the State relies on for its Hybrid estimate.

1389. The State is correct that there is no rational explanation for why the staffing Hybrid numbers changed so radically between AFE 180 and the October 2002 Decision Document. Especially in light of the fact that there was no longer any work being done on Hybrid and the shift had focused on electrification. Johnson testified that the staffing information was developed in August and September 2002,[644] but he could not substantiate his numbers and he had no knowledge of Bailey[645] or Kenonics,[646] he did not consult with any outside automation experts, or visit any automated pipelines. Exs. SOA-688; SOA-689; SOA-743 and SOA-746. In addition, he did not have any experience with the types of control systems that would have been used with the Hybrid option. Tr. 8233:12-14. He only had a "rudimentary understanding of what's meant by predictive maintenance. Ex. SOA-689 at 7:24-25; *see also* Tr. 6786:11-14; 6788:10-21. Further, Johnson acknowledged his lack of experience with control system upgrade projects that would automate pump stations. Tr. 8157:8-12. His team also was inexperienced with automated pump station systems and lacked the basic knowledge required to make an informed decision regarding the number of staff reductions that could be achieved under Hybrid. Tr. 6790:10-23. The team lacked knowledge regarding which buildings would be removed and equipment automated under the Hybrid and Electrification options.[647] Moreover, the staffing analysis was performed in the fall of 2002, before preliminary engineering was started. Tr. 6789:1-5. In his first involvement with the SR project (an August 2002 meeting with Pomeroy and Howitt) Johnson was told that "a good share of the buildings would go out of service with electrification." Tr. 8209:2-7. However, as described above, electrification added a large number of facilities and processes to each

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[642] Tr. 7836:14-7838:25.

[643] Ex. SOA-135 at 16 (Operations was part of the process and endorsed Bailey). Ex. SOA-153 at 18. Estimated approximately four years to complete.

[644] Tr. 8228:10-12.

[645] Tr. 8185:18-8186:2; 8195:8-10.

[646] Tr. 8187:8-18.

[647] Compare Ex. SOA-681 at 3 with SOA-681 at 4; Ex. SOA-682 at 3 with SOA-682 at 5, 6; Ex. SOA-683 at 3 with SOA-683 at 4.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

pump station. Exs. SOA-679 and SOA-680. Yaegge testified that the project was never intended to remove buildings. Tr. 4698:19-21.

1390. The Carriers claim that Johnson and his team had over 150 years of experience operating and maintaining TAPS. Carriers IB 105. However, again the Carriers' assertion is meritless. The team had no experience with staffing reductions achieved through automation. Tr. 8206:5-8208:20. Moreover, the record is devoid of any documentation supporting any of Johnson's claims. The State is correct that the use of individuals with no automated pump station experience and no knowledge of the automation analyses and plans developed for TAPS over eight years, included in the Bailey Report and AFE 180,[648] was unreasonable. The only rational conclusion and finding is that the numbers were made up to justify electrification, and were biased towards electrification. The State is also correct, that the Carriers claim that "Alyeska Pipeline Operations determined in October 2002 that full de-manning of the pump stations under a scenario that left the legacy station equipment in place was not possible without unduly putting pipeline safety and reliability at risk"[649] is unsupported. First, this is contrary to the conclusions reached in the Bailey report and AFE 180. There is no in-depth analysis or study to support the Carriers' claims.

1391. There is no evidence that any further Hybrid studies were undertaken after October 2002 when Johnson's study was completed. However, Hybrid staff reductions were diminished even further in the presentation the SR PMT made to the Carriers in October 2003 in support of electrification. Ex. ATC-200 at 36-37. Specifically, in October 2002 Johnson estimated 140 company-wide staff reductions with hybrid. However, by October 2003, in a presentation to the Carriers hybrid only had 49 company-wide reductions. Ex. ATC-200 at 23-37; ATC-891 at 13:14-19; ATC-19 at 75:16-18. Again there is no evidence to support these numbers and the drop in staff reductions is not explained. Howitt claimed in his pre-filed testimony the 49 total staff reductions number (Ex. ATC-19 at 75:16-18.), however he provided no support for this figure and on cross-examination he testified that he did not make any substantive decisions during the staffing analysis process. Tr. 6783:5-20. It is found that this number is not supported by any evidence in this record.

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[648] Contrary to the Carriers' claims (that Hybrid would have required maintaining approximately 30 turbines), the record supports the finding that since November 2000 reduction of the pump station facility footprints and the number of turbines had been studied. Ex. SOA-151 at 47. To wit, power generation reduced to two units per facility with one being a full redundant spare. This would reduce the amount of equipment requiring maintenance and the amount of energy required for the facility. Ex. SOA-151 at 47.

[649] Carriers IB 102.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1392. The Carriers also assert that the staffing numbers are the result of round-the-clock staffing at the pump stations for hybrid. Carriers IB 114. This claim is meritless. The upgraded control systems that allowed automation and remote operation, along with regional maintenance and oil spill response were the primary drivers to SR staff reductions and all of this could be done under hybrid. Pomeroy acknowledge that the link between upgraded controls and transitioning to regional maintenance and oil spill response was a significant step in staffing the pipeline. Tr. 7882. However, as the State points out, significant steps had been done by Alyeska during the development of AFE 180 in May 2000,[650] before the shift to electrification. The record supports this. Thus it is found that the record shows that Hybrid would have allowed comparable staff reductions to electrification.

1393. Additionally, the Carriers claim that a combination of improvements, including enhanced recirculation capability and replacement of corrosion-prone, below ground piping with above-ground piping, "gave Alyeska management the comfort level necessary to commit to un-manned station operation in the electrification case[.]" Carriers IB 109. The State is correct that recirculation capability and replacement of below ground piping were not part of the electrification scope reviewed by Johnson prior to his preparing his staffing estimates. The record does not support the Carriers assertions. As the State points out, recirculation could have been added to hybrid if it in fact had the prospect of reducing staffing. The legacy pumping equipment has recirculation capabilities. Evidence of this is the January 2011 leak incident where the Carriers used the legacy equipment including an Avon turbine, to recirculate oil at PS 7 during the incident. Ex. SOA-542 at 77:22-78:3. In addition, they are currently upgrading the recirculation capability of the legacy equipment at PS 7 to "[r]estart . . . the pipeline after a winter shutdown." Ex. SOA-607 at 1; *see also* Ex. AT-270. Further, the State is correct that there is no evidence in the record that would attribute any increased staffing needs to maintaining below-ground piping. Sanders testified that "above ground piping provides similar challenges to buried piping in considering ambient temperatures, access due to insulation, integrity of coatings from local environmental conditions, and other concerns. Ex. SOA-542 at 76:22-77:2.

1394. Dr. Boyce's testimony that electrification would require higher staffing numbers than hybrid is entitled to significant weight. Dr. Boyce testified that this is due to the addition of an entirely new area of required engineering expertise in order to maintain the new electric motors. Ex. SOA-543 at 59:16-17. This witness has over "50 years of experience in the field of pipeline pumping stations, power plant engineering and turbomachinery" and has "[f]or the past thirty years . . . provided consultation services to pipeline companies relating to the design of pipeline stations and power plants." Ex. SOA-543 at 2. This expertise makes him more than amply qualified to testify on this matter.

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[650] Ex. SOA-153.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1395. The Carriers dispute the conclusions reached by Dr. Boyce regarding electrification staffing by claiming that Howitt showed that Alyeska actually uses 17 engineering FTE ("full time equivalents"), 35 maintenance technicians FTE's and one scheduler FTE, for a total of 53, to perform these tasks at the three currently electrified pump stations. Carriers IB 108. The State avers that the Carriers' comparison of FTE's to actual people is not a valid comparison. The State points out that Howitt testified that FTE is not the same as people. Tr. 6794:7-9. FTE's simply accounts for the amount of time an individual spends on a given task, which can be represented in hours or fractions of days. Howitt admitted that the 53 FTE figure was roughly equivalent to 149 actual Alyeska employees. Tr. 6795:8-6809:25; *see also* Ex. SOA-690. However, this figure does not include 17 "retreads" that have been rehired to work as technicians. Tr. 6810:1-6. Dr. Boyce's numbers of 96 total employees required to safely operate three electrified pump stations, accounted for the number of persons required to complete the given tasks, which is more than the number of FTEs because it accounts for the various shifts employed by Alyeska (e.g. Field and Urban schedules) to facilitate work at remote pump stations. Ex. SOA-543 at 65:14-15. Conversely, the figures cited by the Carriers'[651] are misleading because they do not take into account "overhired" technicians that are being trained to replace anticipated retirees[652] or "retreads."[653] Moreover, Howitt's figures are artificially low because they do not account for outsourced overhaul work, such as on the Siemens turbine generator and the VFDs, which must be completed by contractors because Alyeska technicians do not have the skill sets necessary to do the work.[654] Dr. Boyce's staffing figures included personnel who would have performed this outsourced work in-house.

1396. The Carriers argue that Hybrid would have required more maintenance and thus, more staff. However, this is an unsubstantiated allegation without any specificity of what exactly that extra maintenance would be and how many more people would be needed. Moreover, the Carriers do not dispute the findings of the Bailey Report or the AFE 180 projections. However, AFE 180 projected a flexible and non-stationary maintenance team based on the upgraded automation. Ex. SOA-153 at 17. Further, AFE 180 stated that the "upgrades will significantly change the requirements of the company's workforce in terms of both skill sets possessed and number of employees. These changes in the required skill level and number of employees are expected to have significant impacts not only in Operations and Maintenance groups but also the majority of the company's support groups. Ex. SOA-153 at 17. This shows that maintenance and

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[651] Carriers IB 110.

[652] Tr. 6810:1-6; Ex. ATC-917 at 27:9-13.

[653] Tr. 6810:7-6812:9.

[654] *See id.* at 6807:9-6808:2; 6809:4-12; *see* also Ex. SOA-692 at 6-7.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

support staff would change based on the lower numbers of employees. The Carriers have not produced any evidence to refute the conclusions in Bailey, Kenonics of AFE 180. Further, Johnson the person who came up with the 2002 Hybrid numbers had no experience with the types of control systems intended for Hybrid. Tr. 8233:12-14. He only had a rudimentary understanding of predictive maintenance. Ex. SOA-689 at 7:24-25. Additionally, no one on his team had any experience with the types of systems that would be used to automate TAPS under the Hybrid option[655] and his group did not do any consultation of subject matter experts. Tr. 8208:21-25. Johnson was unaware that Bailey provided detailed specifications for automation of all the pump station equipment, not just the MLUs. Thus, the State is correct that Johnson's staffing numbers were produced in a vacuum, separate from the previous substantial engineering that had been done on this subject. The State is also correct that based on the evidence in this record it is found that Johnson was not qualified (nor did he attempt to acquire the knowledge to allow him to become a little more knowledgeable) to assess the maintenance requirements under Hybrid.

1397. Dr. Boyce testified that under "both Electrification and Hybrid, the pump stations would be automated and controlled remotely[,] and [b]oth Electrification and Hybrid would use a regionalized approach to maintenance and oil spill response[,]…[t]hus, for each position on these critical teams, four members are required to provide the needed coverage." Ex. SOA-543 at 59:15-23. Additionally, Dr. Boyce concluded that Electrification would actually require 28 more staff than Hybrid due to the fact that "under Electrification there are two new categories of equipment added to the system: the Variable Frequency Drives ("VFD") and the large electric motors," each of which require "totally separate skills of expertise" than the equipment currently in use and thus "some of the teams would need to include engineers and other personnel familiar with electric motors and VFDs to address problems with the new equipment." *Id.* at 59-60. This testimony by Dr. Boyce is consistent with the record evidence in this case. He was a credible witness and his testimony is given significant weight.

1398. The Carriers own evidence shows that project staff reductions under Electrification, were attributed to automation and regionalized oil spill response and not electrification. This would be achievable through Hybrid. Ex. SOA-153 at 7, 17. *See discussion above*. BP's Pump Station Electrification Project Sanction Memorandum discusses the fact that "[o]ne of the enablers of pump station manpower reductions is the new oil spill plan" "[t]he resulting automation provides an opportunity for a step-change reduction of 285 full-time positions," and concluded that "[n]ew automation will enable elimination of field-based pipeline operating personnel, reduce support costs and deliver a $44 million ($17m BP net) per annum cost reduction by 2008 from current levels." Ex. ATC-261 (emphasis added). G. Shotts, Alyeska Operations and Maintenance Supervisor and Maintenance Transition Lead, also attributed staff savings to automation. Ex. SOA-

[655] Tr. 8206:5-8208:20.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

522 at 47. Consequently, it is found that the driver for the staff savings were automation and regionalization of the oil spill and maintenance functions.[656]

1399. The Carriers argue that PS 3 is unmanned. The State argues that the Carriers have not really achieved full "unmanned operation" of the new equipment at any location. Indeed, the entry and exit logs produced in this record show PS 3 had multiple employees nearly every day during the period in the record, and on some days as many as a dozen employees apparently working at the pump station (some seemed to have stayed overnight at the pump station). Ex. SOA-706 (entry for Edgar logged in September 14 and checked out 364 hours later on Sept 29).[657] B. Howitt's testimony that PS 3 was unmanned[658] was totally discredited at the hearing. He conceded he had not entered the station,[659] he admitted that at a minimum a utility rover was required to be working at the pump station[660], and he conceded based on the logs, that significant numbers of people are at PS 3 on a daily basis.[661] The Carriers admitted that the "process area gate" to the pump station is "frequently opened" to "facilitate work" in the process area where the "power generation," the pumps, and the new SR equipment" are located. Tr. 6958:20-6959:1.

1400. The State is correct that the record shows that the "concept" of unmanned is ephemeral based on this record. The Carriers have not showed that they have achieved

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[656] The Carriers argue that while electrification has in fact achieved the personnel reductions which it intended to realize, the same reductions under hybrid would have impaired the safety and reliability of the pipeline. Carriers IB 102, 113. Staff posits that this is a hindsight argument and the Carriers cannot benefit from hindsight while ignoring the delays, cost overruns, and other negative outcomes of SR which confirm that it did not pan out. In addition, Staff argues that the evidence establishes that hybrid would have accomplished the same personnel reductions as electrification. Staff RB 27. Staff cites Dr. Boyce's testimony that the personnel savings were a function of automation of the control systems and regionalized maintenance and oil spill response, and had nothing to do with the use of electric turbines versus the legacy turbines. Ex. SOA-543 at 59. Thus, the staff reductions under hybrid would not have impaired the safety and reliability of TAPS since the reductions were attributable to the safety and reliability upgrades unconnected with the choice of electric turbines. Staff is correct.

[657] The gate logs contain 66 pages of entries and exits at PS 3 for September 2011.

[658] Ex. ATC-19 at 100:20.

[659] Tr. 6881:9-21.

[660] Tr. 6883:22-6884:3.

[661] Tr. 6907:8-10.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

unmanned operations under electrification. The record in this case shows that electrification has not reduced the overall pump station operations staffing at PS 3, 4 and 9. PS 3 now has 0 technicians, around 2002 it had 17; PS 4 now has 34 technicians, around 2002 it had 17; PS 9 now has 14 technicians, around 2002 it had 15. The total technicians at these pump stations around 2002 was 49 now there are 48. SOA IB 231. Compare Ex. SOA-741 (staffing circa 2002) with Ex. SOA-697(current staffing). Maintenance personnel continue to be day-shift only. Tr. 6839:2-11. Now maintenance personnel have their work planned and scheduled from maintenance bases located within the pump station security fences. The Galbraith Maintenance Base is located at PS 4. Tr. 6852:7-14. Maintenance personnel operate out of the same facilities before and after electrification. Tr. 6849:5-6850:2. The oil spill response personnel and emergency preparedness are now in regional maintenance centers. Ex. ATC-250 at 7. Accordingly, it is found that the State is correct that the Carriers have not proved that they are entitled to any mitigation credit for staff savings based on electrification. Further their own evidence shows that Hybrid would have produced similar savings.

1401. In a 2009 document, after reconfiguration has been completed at PSs 9, 3 and 4 the description of crews states: "crews vary per station, typically six to 25 employees. Shifts: one week on/one week off, or two weeks on/two weeks off, depending on station." Ex. SOA-427 at 27. This does not support the Carriers contention that the stations are unmanned.

1402. The Carriers argue that the State's Hybrid estimate cannot be relied upon because "[t]he State's witnesses did not undertake the additional engineering that they say would have been necessary[.]" Carriers IB 226. The State posits that it is not required to perform preliminary engineering on the Hybrid option, at an estimated cost of over $4 million,[662] that the Carriers' themselves failed to perform on the Hybrid option. Ex. SOA-185 at 9. The State continues to respond that it is the Carriers burden to prove any mitigation credit to reduce any disallowance. The State also avers that if the Carriers are dissatisfied with the State's estimates, they have the burden to proffer credible evidence that supports a different estimate since it is their burden to prove that any costs in rates are not imprudent and their attack on the State's estimates are really generic and not specific. In addition, the State contends that the Carriers are in the best position to prove what engineering they did on hybrid to defeat the State's numbers. Finally the State avers that the only alternative to using the State's Hybrid estimate to quantify mitigation is to disallow all of the costs of SR since the Carriers have failed to prove any prudent costs incurred in mitigation.[663]

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[662] Ex. SOA-185 at 9.

[663] The Carriers have abandoned their claims that the cost estimate it commissioned from Stantec Consulting should be used. It was not discussed in their IB. The State argues that if they were to argue it in their RB, it should be disregarded. As the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1403. The Carriers savings projections for electrification were contrary to contemporaneous opinions held by Alyeska operations personnel in charge of maintaining the legacy equipment. For instance, J. DeHaas and L. Monthei, believed electrification would result in either the same or increased major maintenance levels. Exs. SOA-560 at 2; SOA-284. Electrification would not result in decreased major maintenance expenses because very little of Alyeska's major maintenance "has to do with main line units." Tr. 3071:24-25. The State points out correctly, that concerning maintenance of the control systems, there is no justification for the Carriers to claim a difference between hybrid and electrification, because under both options TAPS would have had new control systems. *Compare* Ex. SOA-28, 12, 26 *with* Ex. SOA-60 at 5. The record does not support the Carriers contention that electrification would save $175.5 million more than hybrid over a 20 year planning period. Carriers IB 223. The record does not contain documents showing who or how the savings were estimated. Moreover, it appears DeHaas was not on the team that put together the estimates based on his emails. The Carriers had no witnesses to validate the estimates and Howitt acknowledge on cross examination that he did not have a substantive role in the process and did not make any of the decisions himself. Tr. 6965:8-21.

1404. The State is correct that the maintenance savings are unproven figures inflated by arbitrary escalation percentages. Tr. 6978:24-6979:10; 6983:13-23. Over $50 million of the estimated major maintenance savings for electrification over hybrid were not based on any specific estimate of actual major maintenance tasks. Instead, they were based upon the application of an "unidentified [major] maintenance multiplier" that added 10% to the major maintenance figure in year 1, 30% in year 2, and 50% each year thereafter to account for "new types of maintenance" on existing equipment. Tr. 6978:24-6979:10; *see also* Exs. SOA-13 at 9; ATC-245. The multiplier was applied to both hybrid and electrification. However, the base maintenance for hybrid was higher which resulted in inflation of the hybrid major maintenance figures.

State points out in its IB 22-23, the Stantec estimate is a wholly unreliable, rough order of magnitude estimate based on "budgetary pricing." The consulting firm created the estimate for what it terms is "an important and valued client." In soliciting pricing from vendors it gave an instruction to at least one vendor that: "if there is a significant price difference . . . then default to the higher cost option." Ex. ATC-610 at 31. The Carriers did argue in reply that the Stantec work establishes that if they had pursued hybrid they would now be faced with lifecycle replacement costs in the range of $150 million per pump station to replace much of the legacy equipment that would have been left in place. Thus, the Carriers assert that the lifecycle replacement costs should be considered as incremental benefits in the disallowance calculations. Carriers RB 138. The State's arguments apply to this also, this study is too speculative and hindsight analysis of hybrid.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1405. The Carriers in their IB 223 aver that major maintenance dropped from $94.8 million in 2002 to $76.4 million in 2003 as a result of SR. However, the State is correct that this $18.4 million major maintenance decrease cannot be attributed to SR since the first pump station was not operational until February 2007. Ex. SOA-351 at 2. The Carriers also argue that major maintenance savings form 2003-2009 is evidence that the major maintenance savings were achieved. Carriers IB 223. Again, electric motors were not operational in 2003-2006, thus any alleged savings cannot be attributed to electrification. Moreover, State witness C. Sullivan testified that major maintenance increased from 2007 to 2008, the first full year after start-up of the electrified equipment at PSs 3 and 9. Exs. SOA-545 at 25-26; SOA-622. Sullivan's testimony is given significant weight. In their reply brief the Carriers argue that since the hybrid estimate proffered by the State is not supportable, the presumption of prudence remains and no disallowance should be made.[664]

Disallowance for Execution

1406. The State asserts, contrary to the Carriers' claim that the project was "organized and undertaken exactly as would be expected[,]"[665] that the Carriers' imprudent execution of the SR Project increased costs by at least $153.6 million (excluding PS 1) above what a prudently managed project would have cost (from $421.5 million for a prudently executed project) to $575.1 million (the amount spent so far excluding PS1). Ex. SOA-546 at 2:5-8. The State argues that the Carriers' own documents demonstrate that they mismanaged the execution phase of SR from start to finish. It is understood that this is an alternative remedy were the sanction of the project deemed prudent.

1407. According to the State, beginning electrification before an adequate level of engineering was completed, rushing to achieve an unrealistic schedule and ineffective project management and procedures show that the Carriers were imprudent in the execution of the project. Further, the State asserts that the Carriers' imprudent execution of the SR Project increased costs by at least $153.6 million (excluding PS 1) above what a prudently managed project would have cost (the $153 is the difference between $421.5 million for a prudently executed project and $575.1 million the amount spent so far excluding PS1). Thus the State asserts that $153.6 million is a reasonable disallowance of imprudent costs incurred in imprudent execution of the project after detailed engineering. For PS 1 the State maintains that any costs that the Carriers incur above $152.5 million would be a result of imprudent execution of the project at PS 1 and should be disallowed.

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[664] As stated above, the disallowance argument is irrelevant to the burden of proof argument under prudence. The presumption of prudence was rebutted in this case and the Carriers had the burden of proving which costs should be allowed because they were prudently incurred.

[665] Carriers IB 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1408. The State starts from the July 2005 estimate for electrification or $524.6 million at completion. *See* Ex. SOA-398. The State argues that this is the point at which detailed engineering and FEL were finally completed, and thus it is a reasonable starting point for the State's estimates since this is the first cost estimate developed to the level of certainty (+/- 10%) that the Carriers own protocols require. Ex. SOA-275 at 157-58. This July 2005 estimate includes AFE S020 supplements 1 and 2. The Carriers' documents at the time of approval of Supplement 2 confirm that if they had done sufficient engineering prior to initial sanction, they would have arrived at the $524.6 million figure at that time. For instance, the Final draft of AFE S020 dated July 28, 2005, states the "project was always going to cost this much to complete, however, that was not fully understood until detailed engineering was substantially complete." Ex. AT-219 at 6. A BP internal funding memorandum dated August 2005, confirms this and that this was not fully understood at the time of sanction. Ex. SOA-11 at 20. At sanction, the Carriers did not understand the true costs of the project because sufficient engineering work had not been done. A prudent manager would have required sufficient engineering before sanction.

1409. C. Sullivan adjusted the costs consistent with his prior adjustments. State witnesses determined that had the SR project been properly executed it would had been completed by April 2008 (instead of the third quarter of 2006 as estimated by the Carriers on July 2005). This assumption extends the schedule by 19 months. *See* Ex. SOA-546 at 15-16. C. Sullivan next multiplied the Carriers own estimate of the cost of schedule extension or $1.4 million per month by 19 months for a total of $25.5 million in additional costs.[666] He then added $23.9 million for unavoidable costs (increased labor, price changes and logistics) based on the Carriers' own calculations in AFE SO20 Supplement 3. *See* Ex. SOA-546 at 15-18. The Carriers attributed $13 million to labor rates, $4 million to price changes and $3.1 million for logistics.[667] Additionally, he removed PS 1 costs of $152.5 million by applying a cost ratio for PS 1 (26.56% of

[666] The Carriers estimated the cost of schedule extension at $1.4 million per month for all pump stations. *See* Ex. SOA-65 at 34. The State witnesses total for 19 months was $21.7 million. To this figure they added $3.8 million for costs associated with JPO staff project oversight and Alyeska's commissioning staff. Ex. SOA-546 at 16-18.

[667] The State experts prorated these costs to account for unavoidable costs on all SR-related projects using a ratio of 1.19. This ratio is the ratio between the estimated "All-in" Capital Cost at July 2005 of $476 million and the estimated capital cost at July 2005 for just Pump Station 1, 3, 4 and 9 of $400.1 million. The 1.19 ratio was applied to the unavoidable costs identified in AFE SO20 Supplement 3 to determine the total unavoidable costs for all electrification projects. SOA IB 256; *see* Ex. SOA-398.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

overall electrification costs).[668] This adds up to $421.5 million of prudently executed cost of electrification excluding PS 1.

1410. The State argues that its $153.6 million disallowance is reasonable since the Carriers themselves found execution mismanagement costs in the range of $157 million to $186.6 million post supplement 2.[669] According to the State, these estimates are between $3.4 million and $33 million higher than the amount proposed by the State. In February 2008 in a review, BP attributed $157 million (gross) in post-supplement 2 cost increases caused by unreasonable project management and execution. The following factors were listed by BP as factors that drove the cost increases: (1) additional scope; (2) materials/equipment not in the original project estimate; (3) rework/inefficiencies; (4) engineering/construction errors; (5) deferral (PS No. 1 related); (6) deferral (post 2006) and (7) not yet categorized. Ex. SOA-571 at 18. The majority of these costs are attributable to unreasonable project management and execution, according to the State. SOA IB 258.

1411. For instance, the State maintains that additional scope, and "materials/equipment not in the original estimate" are endemic to the Carriers' failure to complete sufficient project engineering prior to construction which would have defined scope, as well as the failure to implement a MOC and enforce scope freeze procedures which would have mitigated these additional costs. SOA IB 258. Rework/inefficiencies and engineering/construction errors are the result of insufficient project planning prior to construction and failure to adequately manage the Carriers' contractors performing and supervising the field construction. Further, the State avers that deferral costs are due to the push to complete the project based on unrealistic deadlines. A prudently managed project would have set a reasonable schedule and completed the project by April 2008 avoiding deferral costs, according to the State. SOA IB 259.

1412. Likewise, the State asserts that Conoco's internal review attributed at least $52.8 million (net, representing its ownership share) to factors related to mismanagement to the project after Supplement 2. Ex. SOA-209 at 9. According to the State, this is $186.6 million or $52.8 divided by its share 28.3%. The cost increase was due to (1) incomplete engineering; (2) inadequate project management and project controls; (3) turbine corrosion; and (4) scope changes. *Id.* Conoco found that engineering was not 90% complete as reported at Supplement 2 but instead was only 60% complete. The failure to

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[668] The ratio was developed by taking the ratio of the projected cost of PS 1 to the projected total cost of the project at prudent sanction. Exs. SOA-551 at 34 and SOA-546 at 19-20. A ratio was developed because the majority of the Carriers' costs are not itemized by pump station. Ex. SOA-546 at 19-20.

[669] Contrary to the Carrier's assertions, the State does not concede that the cost growth experienced from sanction up to AFE S020 was prudent or that the cost growth after Supplement 2 was unavoidable. Carriers RB 44.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

properly complete engineering resulted in delays that "caused increased program cost, reduced productivity and hyperinflation." *Id.* Additionally, Conoco found that this required additional corrections to be made in the field, and inefficiently shifted the work location form the shop to the field because modules were not fully completed in the shop prior to shipping. *Id.* In addition, Conoco states that inadequate project management and project controls resulted in a failure to complete a value-improving front-end loading process, led to putting in place a post-supplement 2 project team that "lacked large project experience," and led to failure to control changes, leading to massive cost increases. Ex. SOA-210 at 8. According to Conoco, turbine corrosion occurred as a result of the failure to properly warehouse equipment, leading to further cost increases. *Id.* Conoco also found that scope changes resulted from incomplete engineering, and late operations engagement. *Id.*

1413. A similar internal review by Exxon attributes $37 million in (net) cost increases to factors related to mismanagement of the project after 2005. This is $182.3 million gross ($37 million divided by 20.3%). Ex. SOA-211 at 4. Exxon attributed the cost increases to scope and design changes occurring during construction. *Id.*

1414. The State argues that it is appropriate to use hindsight documents to analyze decisions after the decisions were made, to quantify the consequences of an imprudent decision. The Carriers agree, avers the State, that hindsight may be used to calculate the consequences of imprudence citing the testimony of D. Toof. Ex. ATC-36 at 88:1-4, *see also* Ex. ATC-30 at 40:12-13.

1415. Dr. Horst a State witness provided a methodology for removing imprudent costs from the Carriers' rates. Ex. SOA-548 at 4-5. The estimated Hybrid cost spent by year are shown at page 263 of the State's IB. Dr. Horst testified that the operating expenses for 2008 for the "prudently managed" electrification should be amortized over a five-year period because they would not be recurring. Ex. SOA-548 at 18:8-19:22. He also recommended that the cost of capital in the rate model be adjusted to reflect the parties' cost of capital stipulation. *Id.* at 14:6-18. Further, he asserts that the same cost of capital adjustments should be made to the cost of capital components used in calculating the debt and equity components of AFUDC for 2008 in the rate model. *Id.* at 14:19-15:13. The State argues that the Carriers should be ordered to follow Dr. Horst's methodology in any compliance fillings in this case since it removes the costs of the Carriers' imprudence from the rates. Additionally, that the Carriers should be limited to $37.3 million in costs for PS 1 in any future rate filings. This amount, the State posits, is what reconfiguration of PS 1 would have cost had the Carriers pursued Hybrid. The State request refunds in its remedy. The State cites *Conn. Valley Elec. Co., Inc. v. FERC*, 208 F. 3d 1037, 1044 (D.C. Cir. 2000) and *Towns of Concord, Norwood & Wellesley, Mass. V. FERC*, 955 F. 2d 67, 76 (D.C. Cir. 1992) for the proposition that the agency has wide discretion to fashion remedies in this case.

1416. The State argues that the Carriers had two points of disagreement with Dr. Horst's methodology: his calculations concerning PS 1 and the "differences in methodology

20140227-3052 FERC PDF (Unofficial) 02/27/2014

required for RCA filings" that were not addressed by Dr. Horst. Carriers IB 257. The State is correct that the Carriers's arguments are unsubstantiated. Consequently, the Carriers arguments concerning Dr. Horst's methodology are rejected. The State asserts that the Carriers had to put forth their own explanation and justification for their costs and their failure to do so means that they have not met their burden and the costs should be disallowed in the rates. The State in response to the Carriers arguments asserts that it only has to show a nexus between the Carriers' imprudence and the challenged costs. It avers that the Carriers' misstate the prudence standard and that it is not appropriate to require protestants to prove the imprudence of each alleged cost because the evidence regarding any expenditure is in the hands of the utility and not the parties challenging the expenditure. The State cites to *Iroquois Gas*, 87 FERC at ¶ 62,169 for this proposition. The State avers that in this particular case it would be unreasonable to require the State to trace each act of imprudence to each cost of imprudence where "[c]ost data was not recorded and tracked by Alyeska or the Carriers based on each event, action, or issue that involved the project. Therefore, quantifying each and every imprudent decision is not possible with any reasonable degree of accuracy. Ex. SOA-546 at 26:6-8. The State is correct. *See* discussion above on burden of proof.

1417. The State also argues in response to the Carriers,[670] that it did not use a Total Cost or Modified Cost Approach to determine the subset of imprudent costs for imprudent execution. State RB 142. Adams testified that his approach highlighted "the reason for the unplanned and excessive cost," and was not merely a calculation of the difference between a bid price and actual price. The State avers that its costs were corroborated by the Carriers own assessment. To wit, BP's internal review finding $157 million in additional costs as a result of items including unidentified scope and materials, inefficiencies, and deferral. Ex. SOA-571 at 18. Additionally, the finding of $224 million in similar mismanagements costs. Ex. SOA-546 at 29:4-13. Further, the finding of $182.3 million in similar mismanagement costs. *Id.* at 31:20-32:2. The State additionally argues that the Carriers cannot shift their burden to the State and that it is the Carriers burden to trace costs to their origins and show that they are not the product of imprudence. The State concludes that the Carriers have failed to prove that any of the electrification costs were not infected with imprudence. Again, it is concluded that the State is correct.

1418. In terms of the State's specific prudently managed cost estimate it does not agree with the Carriers' assertion that $14.1 million should be added for "outside contractors' time-sensitive costs." The State claims that the Carriers failed to identify what these costs would entail and prove that they should be added. State's RB 144. The State also disagrees that the $11 million for "[C]ontractor [E]rrors and [O]missions," $12 million for "[N]ewly [I]dentified [W]ork," and $3 million for "[P]roductivity [L]osses" should be included in unavoidable costs. The State argues that as their name suggests these costs

[670] Carriers IB 239.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

would have been avoided through proper planning and management. It further argues, that the Carriers failed to demonstrate that these costs were prudently incurred. State RB 145. As State witness Adams testified, the costs for "[E]rrors and [O]missions" were the result of avoidable contractor and owner deficiencies. Ex. SOA-546 at 25:6-9. He also testified that "Newly Identified Work" is another name for avoidable design gaps and should not be included. If sufficient engineering had been done, these design gaps would have been identified prior to sanction. Adams also testified that "Productivity Impacts" were the result of reduced labor productivity due to Alyeska's poor planning and deficient execution, and should not be included in the Proper Project Estimate. *Id*. at 25:16-21. The State is correct.

1419. Additionally, the State points out that the State's prudently managed SR project estimate assumes that the pump stations have been completed sequentially. According to the State, the "phasing of the construction should have resulted in reduced overtime, the use of fewer work crews simultaneously (spreading the cost rather than increasing it) and improved labor productivity, which would have saved costs. Thus, the State argues in response to the Carriers' arguments, that including additional costs for the sequential completion would be double counting.

1420. The State used a ratio to calculate the PS 1 costs and the Carriers assert that the State should have used a ratio based solely on construction costs as opposed to total costs. The State argues that the Carriers have not offered any credible evidence that using the ratio calculated by the State is unreasonable. Moreover, the difference between the two suggested methods is minimal. The State' suggested ratio is 26.56%, the Carriers' 23.3%. The State argues, that the Carriers' did not offer any evidence or explanation for their expert's proposal to apply the ratio to certain AFE's and not others and thus, the proposal should be rejected.

1421. According to Anadarko, the Commission has an obligation to provide a remedy for unjust and unreasonable rates. The Carriers were imprudent and otherwise unreasonable in their design, approval, management, and construction of the SR project. It further asserts that the project is not used and useful or beneficial to ratepayers. Anadarko maintains that SR is a failed project. As a result, the filed rates include imprudent and unreasonable costs and are not just and reasonable and therefore are unlawful. Anadarko asserts that the Commission has an obligation to remedy unjust and unreasonable rates citing *Office of Consumers Counsel v. FERC,* 783 F. 2d 206, 233-236 (D.C. Cir 1986); Cf. *Consol. Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 967 (D.C. Cir 2003). Citing *Niagara Mohawk Power Corp. v. FPC,* 379 F. 2d 153, at 159 (D.C. Cir 1967) Anadarko argues that the Commission has discretion in fashioning remedies. A regulated entity cannot recover costs incurred imprudently. *Violet*, 800 F.2d at 282. The typical remedy is to exclude from rates costs imprudently incurred. *Enbridge Pipeline (KPC),* 100 FERC ¶ 61,260 at PP 337-340 (2002); *Columbia Gas Transmission Corp.,* 42 FERC ¶ 61,021 (1988) aff'd sub nom. *Office of Consumers Counsel v. FERC,* 842 F. 2d 1308 (D.C. Cir 1988).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1422. Additionally, costs are removed from rates if not used and useful, not beneficial to ratepayers, are the product of a failed project or violate the principles of intergenerational equity. Anadarko maintains that any uncertainties in the record regarding the proper amount of costs to be excluded from rates must be resolved against the Carriers because this is consistent with the burden of proof. Further, the failure of the Carriers to present relevant evidence to show the prudence and reasonableness of the costs warrants an inference that such evidence would be adverse to the Carriers, according to Anadarko. For instance, the pertinent documents, according to Anadarko, are in the Carriers' control. However, the Carriers failed to provide key evidence such as the BP decision makers for the SR project and J. DeHaas, an a negative inference should be made from this failure.

1423. Anadarko argues that the economic impact of cost exclusion is lessened by the integrated economics of TAPS. The Owners have already paid the costs of SR once and there is no real economic significance within the integrated corporate families from the Carriers' production affiliates paying those costs a second time to the Carriers through transportation rates. According to Anadarko, paying higher TAPS transportation rates lowers the amounts the Carriers's production affiliates pay to the State for royalty and severance taxes. Further, the higher the TAPS rates the Owners recover the greater rate revenues from independent shippers. Anadarko postulates that under this scenario the principal impact of a rate disallowance on the integrated TAPS entities is not the face value of the disallowance but a fraction of that disallowance equal to: (1) the value of the foregone royalty and severance tax benefits enjoyed by the upstream affiliates (approximately 25%), and (2) the reduced recovery from independent shippers (approximately 5%).[671] *See* Exs. AT-22 at 27-28 and SOA-547 at 23-24.

[671] Tesoro is the only independent shipper, Anadarko ships indirectly through Tesoro. Tesoro's volumes account for about 5% of the total TAPS throughput. The Carriers argue that Anadarko cannot show any impact of SR since it is not a shipper on TAPS. Carriers RB 116. This argument is specious since the Commission gave Anadarko standing to challenge the rate filings since it has a substantial interest in the TAPS rates. *See*, *ExxonMobile Pipeline Co.*, 127 FERC ¶ 61,089, at n.2 (2009); *Unocal Pipeline Co*, 121 FERC ¶ 61,300 (2007); *BP Pipelines*, 117 FERC ¶ 61,352 (2006); *BP Pipelines*, 113 FERC ¶ 61,332 (2005); *BP Pipelines (Alaska) Inc*., 109 FERC ¶ 61,376 at P 10 (2004). Higher rates on TAPS will have an impact on Anadarko's "netback" pricing. Anadarko uses forms of netback pricing to sell its ANS crude oil. Netback pricing is an index price of U.S. West Coast ANS crude oil, less the transportation costs of ANS crude oil from the ANS to the West Coast. The Carriers also argue that Tesoro is mostly an intrastate shipper and has chosen to ship on BPPA's intrastate tariff which is discounted as opposed to shipping on Conoco's or Exxon's tariffs which include SR costs, thus it has not been harmed by SR costs. Carriers RB 116. There is insufficient evidence in this record concerning Tesoro's intrastate shipping at a discounted BPPA intrastate tariff. The cited B. Sullivan testimony does not support this Carrier contention.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1424. Anadarko proposes five alternative remedies and recommends that the remedy place responsibility for the SR failures on the parties who took the risks and controlled the project – the Carriers and their affiliated Owners.[672] For their imprudent actions authorizing SR at PSs 1, 3, 4 and 9 notwithstanding that PS 1 is not yet completed.[673] First, is the exclusion of all the SR capital costs except for SIPPS, this would remove $437.3 million from the TAPS rate base for the 2009 and 2010 rates and future rates.[674] Ex. ATC-628 line 28, $454.4 million total SR costs in rate base minus line 15, $17.1 million SIPPS costs, minus line 23, $17.7 thousand SIPPS completion costs, equals a rate base exclusion of $437.3 million. Under this alternative $0 SR capital costs (other than SIPPS costs) would be allowed in current or future TAPS rates.[675] According to

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[672] According to Anadarko the impact of SR is substantial. According to B. Sullivan the Carriers' depreciation expense and return components of their annual cost of service has increased $104 million from 2006 to 2010. Tr. 349:10-350:13 (second phase). B. Sullivan also stated that the annual cost-of-service will continue to rise as the Carriers continue to spend money on PS 1. The increase in the annual cost of service is primarily attributable to SR. Tr. 350:24-351:5 (second phase). Anadarko's RB 90.

[673] *See, e.g.*, SOA-60, Ex. ATC-279 and Ex. SOA-65.

[674] Anadarko argues that the Carriers failed to support the prudence and reasonableness of the specific SR costs and failed to provide key evidence regarding the project and decision making. For example, the Carriers did not present any of the BP decisonmakers for the SR project even though BP was the largest owner and a force behind the project and did not present Alyeska's top rotating equipment engineer DeHaas. Anadarko asserts that these deficiencies must be construed against the Carriers. The record in this case is sufficient to reach a decision. However, and as stated above, adverse inferences are drawn from the failure to present J. DeHaas and Al Bolea as witness at the hearing.

[675] Anadarko also argues that the automation and control systems upgrades were part of an imprudently planned and executed electrification project which infected all aspects of the overall undertaking thus the costs for automation and control system upgrades should be excluded. As an example, Anadarko states that electrification required that the Carriers implement a sub-optimal control system that could operate both the legacy equipment and the new electrified equipment, adding complexity, inefficiency and increased costs. Tr. 3566:7-3567:5. However, the microwave/fiber optic communications system used by the automation and control system is to be included in rate base since it is leased or an expense item. Tr. 4289:3-14. Communication sensors and cables built in the prefabricated electric pump modules would be removed from rate base along with the costs of those units. Tr. 4289:15-4291:5. Moreover, Anadarko argues that the Carriers failed to justify the costs of automation and control system upgrades, having called the estimates of these costs into question. Tr. 6151:2-22 (Toof

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Anadarko, the Carriers failed to perform adequate engineering to correctly ascertain the scope of SR, and thus the cost of SR is inexcusable.

1425. Anadarko's second remedy proposes the exclusion from rate base of all SR capital costs beyond the initial AFE SO20. Thus the Carriers rates would include a total of $216.3 million of SR capital costs approved in AFE S020. Ex. SOA-60 at 2 ($206.3 million capital plus $10 million previously approved). The capital costs allowed in the rates would be amortized in the cost of service over the remaining useful life of TAPS. Anadarko argues that the Carriers should not be rewarded with an equity return on any capital costs allowed in rates, and any such costs should be amortized in the cost of service (not rate base) over the remaining life of TAPS, with no return allowance. All capital costs above $216.3 million would be excluded from rates, for the 2009 and 2010 rates at issue in this case this would be a rate base exclusion of $238.1 million. The rate base exclusion is calculated as: $454.4 million total SR capital costs in the 2009 and 2010 rates minus the allowed amount $216.3 million equals $238.1 excluded from 2009 and 2010 rates. Ex. ATC-628, line 28. All SR capital costs above $216.3 million would also be excluded from any future TAPS rates. According to Anadarko this proposal obviates the need for further litigation concerning SR. Although PS 1 has not been completed yet, AFE S020 included authorization and costs for PS 1, 3, 4 and 9. Ex. SOA-60.

1426. This option is reasonable, Anadarko argues, because the purpose of the project was to deliver costs reductions. In the absence of those reductions the project failed to deliver anything useful or beneficial to ratepayers. This is different than the typical capital project which delivers tangible benefits such as new capacity, new markets, new supplies, replacement of obsolete equipment, or compliance with a regulatory requirement. Moreover, the cost increases were due to factors within the Carriers' control. The proposal Anadarko continues, captures the fact that cost increases were the result of mismanagement or other causes under the Carriers control. Missed scope and unattainable schedule are examples of factors that were under the Carriers' control and were mismanaged. Further, not providing adequate resources to implement UCOS properly,[676] excluding the input from operations personnel at key planning stages, [677] and installing generators that require "load banks" because they are mis-sized[678] are examples

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testifying that in his opinion "there is not . . . a credible 2005 hybrid number on the table)."

[676] Ex. AT-406 (Eldridge testifying about problems in the system); AT-515 (they tried to rectify deficiencies prior to delivery but only 20% were completed due to time and resource constraints).

[677] Ex. AT-433 at 26 (Hiebert stating her input was not considered); AT-536 (Eldridge with similar testimony); At-429 at 27 (Turnipseed they felt they were not being heard).

[678] Ex. SOA-574 at 4.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of mismanagement. As B. Sullivan testified, increased costs due to mismanagement do not provide ratepayer benefits. Tr. 347:11-24. Thus, this proposal would charitably give the Carriers the costs of the project they believed would be used and useful, while protecting the ratepayers from the increased costs of the poorly executed SR project.

1427. The third remedy proposed by Anadarko is to exclude from rates all SR capital costs included in AFE SO20 Supplement 2 and all SR AFEs thereafter. Capital cost from AFE S020 and Supplement 1 total $229.2 million which would be allowed in rates amortized in the cost of service over the remaining useful life of TAPS. Ex. SOA-64 and SOA-65 at 6. All SR capital costs above $229.2 would be excluded from rates. For 2009 and 2010 rates at issue in this case the rate base exclusion would be $225.2 million. The rate base exclusion is calculated as: $454.4 million total SR capital costs in the 2009 and 2010 rates (Ex. ATC-628, line 28) minus the allowed amount of $229.2 million equals $225.2 million excluded. All SR capital costs above $229.2 million would also be excluded from any future TAPS rates. This remedy will also prevent future litigation of SR costs as all SR capital costs above $229.2 would be disallowed from current and future TAPS rates. Note that AFE S020 and Supplement 1 included PS 1, 3, 4 and 9.

1428. Anadarko postulates that by Supplement 2 the Carriers knew the project was flawed and a "Train Wreck." Ex. AT-252. Supplement 2 approved $168.1 million, bringing the total SR costs to $434.5 million[679] and extended the completion date from 2005 to mid-2007. Supplement 2 nearly doubled the costs while the benefits dependent on project completion by 2005 faded. Ex. SOA-292 at 3; Tr. 3829:2-3830:11. At this point in time the Carriers knew all the risks presented in Hisey's August 2005 risk matrix. Ex. AT-235. The risks included misalignment of the Owners and failure of the Owners to make timely decisions, *Id.*; delays in engineering by SNC and Hinz, *Id.* at 2; late material deliveries, *Id*; poor performance of fabrication and field installation contractors, *Id.*; shortages of craft and management resources, *Id.*; "[u]nknown design issues," *Id.*; problems with delivery and revisions of drawings, *Id.*; unproven "Serial No. 1" pump motors, *Id.*; and other issues. They also knew that the schedule was not achievable. Ex. SOA-237 at 3. Cost increases and delay impacted the project economics. The bonus depreciation tax benefit expired at the end of 2005.

1429. Exxon evaluated the SR project economics at Supplement 2, added $10 million as a "special cost and schedule allowance" and determined that SR had a negative net present value. Ex. ATC-27 at 50-51. In addition, the Carriers knew that the original cost estimates were wrong. One month after AFE S020 Supplement 2 was approved, Flood described the original sanction as follows: "[t]he project team was handed a deadline and conceptual engineering cost estimates that were improperly used as benchmarks. The project was 'boxed' into those parameters instead of being allowed to fully evaluate options, costs, and risks. The resulting cost estimates and probability analyses were not

[679] Ex. SOA-64.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

realistic." Ex. ATC-344 at 1. Tudor recognized at the time of Supplement 2 that there were a number of issues: inaccuracies in original estimates, additions or modifications of project scope, increases in material prices, rework and delay. Ex. ATC-27 at 39. Flood recommended adding $4 million in net capital costs since he believed the cost estimates to complete the project were overly optimistic. Ex. ATC-21 at 25.

1430. Further, the Carriers also knew the project scope was not adequately defined. The scope of the project was not fully established until well into detailed design. Ex. ATC-344. Tudor testified that there was more brownfield work than expected and regulatory requirements were not fully understood and that these factors contributed to both understated costs estimates and to scope changes. Ex. ATC-27 at 40. The primary engineering contractor, SNC, was performing poorly. Ex. SOA-199 and ATC-27 at 40. The project cost controls were deficient. Tudor testified that many cost increases had already occurred by the time they were identified. *Id.* In addition, he testified "when AFE S020, Supplement 2 was submitted, it became clear that the project was going to cost significantly more and take longer to complete." Ex. ATC-27 at 41. The project had been described as a train wreck by BPPA President and his associate and he "wanted advice on how to mitigate going forward . . . including taking a pause to get things back on track." Ex. AT-252. BPPA believed SR was a "performance upset" and a performance bust was right around the corner" that was "clear to the Carriers and regulators."[680] Ex. AT-19 at 9 & n. 17.

1431. At supplement 2, the Carriers knew that SR was a "train wreck," but approved continuing the project thereby increasing its costs significantly. Anadarko maintains this action was imprudent and thus the costs incurred after supplement 2 should not be in the rates. This conclusion is supported by the prudence standard and also the other just and reasonable rate standards discussed by Anadarko. Noteworthy, the fact that they acknowledge the project was a train wreck shows that they knew they were dealing with a failed project particularly with regard to the economic benefits that were the basis for the project. According to Anadarko, the responsibility for failed projects is on shareholders and not ratepayers.

1432. In addition, Anadarko avers that at Supplement 2 it was clear to the Carriers that SR would not provide utility to ratepayers. The Carriers knew that the scope of the project was ill defined, the costs were escalating and the schedule would not be achieved. Additionally, they knew they would not obtain the bonus tax depreciation benefit, which expired at the end of 2005. They knew their original cost estimates were wrong and that the contractors were not performing well. The reasons the Carriers had for moving

[680] The Carriers used "point forward" economics to justify their decision to approve Supplement 2, ignoring sunk costs. However, for rate making purposes the Carriers are including all costs.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

forward with the project[681] were unrelated to utility to ratepayers. Anadarko also argues that at Supplement 2 it was clear that the project would not produce a net or commensurate ratepayer benefit. The economics of SR were marginal to begin with and by Supplement 2 it was clear that SR would cost significantly more than originally projected. The various items discussed above eroded any economic benefits to SR.[682] Gaul had recognized that the economics of SR could be eroded if costs increased by 25 percent yet at Supplement 2 the Carriers were deciding whether to double the costs. At supplement 2 it was clear that the benefit of cost reductions was unattainable. Moreover, the Carriers have never argued that cost increases would be accompanied by commensurate increases in ratepayer benefits. Consequently, doubling the costs of an already failing project at Supplement 2 never had a chance of providing commensurate benefits to ratepayers, according to Anadarko.

1433. The fourth remedy proposes to exclude from rate base all capital costs for the portion of SR related to electrification of the pump stations. The total capital costs to be excluded from rate base for 2009 and 2010 would be $397.1 million.[683] Again Anadarko argues that this remedy would apply to future rates and would eliminate future prudence litigation. The allowed costs would be amortized over the entire life of TAPS. For 2009 and 2010 rates the allowed amount would be $57.3 million. Calculated as follows: $454.4 capital costs in filed rates minus $397.1 million equals $57.3 million in allowed 2009 and 2010 rates.[684] For 2009, the impact of the reduction would be a cost of service reduction

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[681] Booking reserves to upstream affiliates and point-forward economics.

[682] Tudor testifying if the schedule was impacted by more than 10 to 15 percent, the attractiveness of the project would be impacted. Tr. 5036:6-17. Any further scope additions from that point forward would come "close to driving the project over the edge." Ex. SOA-324.

[683] In his testimony, Grasso also proposed a reduction to TAPS operating costs associated with electrification. Ex. AT-225 at 4, 5. However, Anadarko is limiting its remedy to capital costs to simplify the issues for decision and facilitate the implementation of the remedy. Anadarko argues that if any of the decisional bodies were to adopt credits to operating costs for purported SR savings (which would not be justified) they should also disallow any operating costs shown as imprudent as quantified by Grasso and the State witnesses.

[684] The $397.1 million excluded are "actual" capital costs (not estimates). Ex. AT-225 at 4 (Illustration No. 1); Tr. 4258:9-4259:5; 4272:13-14. Quantification of electrification spend was developed by Carrier witness Toof. Ex. AT-228. Electrification capital costs used by Grasso in Ex. AT-225 at 4, Illustration No. 1, are the amounts placed in rate base shown on Ex. AT-228 at 9, line 5. The costs for 2007-2009 are actual costs. *See* Ex. AT-228 at 9, n. 1 and Ex. SOA-582.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of $66 million and for 2010 of $51.3 million. [685] Ex. AT-225 at 6, Illustration No. 2; Tr. 4293:21, 4311:19-4312:14.

1434. Anadarko argues that electrification was ill-conceived, inadequately studied, and rushed. The substantial cost increases due to electrification overshadows any purported and unproven savings from electrification. Moreover, the potential SR cost reductions were projected to result from automation, not electrification and Grasso's proposal would leave automation and control system upgrade costs in rate base. Ex. AT-218 at 19-20; (both electrification and hybrid included control system upgrades that would allow for remote pump station operation and monitoring. The projected staff reduction savings are primarily driven by automation and the ability to operate and monitor the pipeline remotely form the OCC) (Sullivan) SOA-545 at 8; AT-230 at 7-8; Tr. 3072:19-3073:23; Tr. 3903:17-3904:8. *See also* Ex. ATC-102 at 22-24. Anadarko maintains that electrification failed to provide any utility or benefits to ratepayers, definitely not commensurate with the costs of the project. Further, electrification is a failed project for which shareholders should be held accountable.

1435. Conversely, Anadarko argues, the Carriers ignored years of studies showing that electrification was not economic and at best should be tested at PS 9 since it was close to the electric grid. Tr. 1275:23-1277:1. Anadarko continues arguing that the electrification concept was based on the Carriers' self-described "bold" leadership,[686] "break-through thinking,"[687] and "clean sheet" approach,[688] which ignored the extremely reliable and well-functioning gas-powered legacy equipment and proceeded on the false premise that TAPS was being built anew. However, the project scope was underestimated, so were the costs and overstated project benefits.[689] The accelerated schedule was impossible to complete and earlier studies had showed that automation alone would take four to five years. The Carries also by-passed Alyeska's standard project procedures which would have required additional engineering of the electrification option prior to commencement. Tr. 2384:14-2385:5; 3027:22-3028:22; SOA-279 at 4, 10; Ex. SOA-193. Further, the staff of the project team was inadequate, unqualified and ill-equipped for the job, according to Anadarko. Ex. SOA-172 at 2; Ex. SOA-381 at 6, 12; Ex. SOA-217; Ex. SOA-383.

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[685] Grasso's exhibit AT-261 shows additions to Carrier property in service for 2007, 2008 and 2009 and segregates electrification capital costs.

[686] Ex. SOA-466.

[687] Ex. SOA-292 at 3.

[688] Ex. ATC-21 at 11; ATC-19 at 44; ATC-137 at 2; Tr. 4600:16-4602:6.

[689] Ex. AT-218 at 12-15, 19-20; Ex. SOA-121 at 2; SOA-115 at 1; SOA-545 at 24.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1436. Moreover, the project was totally discretionary and did not have to be done at all.[690] Anadarko also argues that it is uncontested that the legacy equipment was functioning in a highly reliable manner and could do so for the planning horizon of the project. Ex. AT-165 at 4; Tr. 4604:8-13; 4779:16-17; 7980:15-7981:3; 7985:11-23; SOA-19 at 2; SOA-21 at 1. Moreover, the maintenance costs for the legacy equipment had been decreasing. Ex. SOA-19. There was a large inventory of spare parts due to the decommissioning of a number of pump stations. Exs. SOA-429 at 15, 24-25; SOA-431 at 245-246; SOA-19 at 2; ATC-19 at 104, 109; Tr. 2963:23-2965:4. Additionally, the legacy equipment had low failure rates and low unplanned shutdowns. Tr. 7981:2 and 7980:15-7981:3.

1437. Anadarko also argues that there were examples showing that electrification was ill-advised. Namely, the Forties Pipeline shows that electrification at remote pumps is ill-advised. At Forties Pipeline the stations are connected to an electric grid, which was not available to TAPS. Tr. 8099:21-25; 8059:3-6; 8024:4-14. Moreover, the Forties retained gas turbines for pump stations located in areas with no access to a grid. Tr. 8099:21-25. Further, B. Sullivan testified that the original TAPS pipeline would have been built with electrified pumps if it had made sense. Tr. 344:16-21.

1438. In its reply brief the State points out that the Carriers attempt to analogize the Forties Pipeline to SR. This fails in addition, according to the State, since it fails to acknowledge that the electric pumps at the Forties Pipeline were designed and built as electric pumps (not converted from gas to electric as SR). State RB 34. Moreover, the State posits that the decision to build a new pipeline with electric motors where electric power is commercially available requires a different analysis than a decision to replace well-functioning turbine driven pumps with new electric pumps at existing, operating stations where electric power is not commercially available. Thus, it is concluded that the Carriers analogy to the Forties Pipeline is not persuasive to demonstrate the "reasonableness" of the Carriers actions.[691]

1439. Anadarko further points out that the scoping white paper for PS 1 shows how ill-advised electrification was. The Siemens generators are not properly sized or is oversized for TAPS service, since the units at all pump stations require load banks to essentially waste surplus energy in order to meet air quality permit requirements. Ex. SOA-574 at 4. At PS 1, if the Siemens Cyclone is installed, it may not be used if throughput remains below 600,000 bpd, where it is today. Tr. 7011:8-11; Ex. SOA-574 at 19. The power load strategy for PS 1 would not place any load on the Siemens Cyclone at throughput below 600,000 bpd. However, as discussed above this paper

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[690] Tr. 4779:16-17; 4604:8-12; ATC-18 at 12; Ex. AT-218 at 11.

[691] *See*, Tr. 8031:17-8032:7 (Pomeroy testifying the PT did not locate a single pipeline in the entire world that was undergoing a conversion from "turbine based to electric."). *See also* Tr. 8073:3-12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

rejects the use of the legacy equipment because it would require writing off $91 million in SR investment. Ex. SOA-574 at 5, 12. Anadarko further argues that this shows that electrification was not used and useful, provides no ratepayer benefits and has failed.

1440. The fifth remedy is that Anadarko supports the State's remedy proposal and the State's alternative remedy. Anadarko argues that while the State sets forth its remedy proposals in terms of prudence, they are also fully supported by other ratemaking principles advocated by Anadarko including the use and useful principle, the ratepayer benefit principle and the failed project principle.

1441. The Carriers' attempt to minimize the impact of the disallowance. Carriers IB 244. For instance, the Carriers criticize certain elements of the State and Anadarko's proposed remedies. In addition, they argue that the State's numbers are not correct including the automation costs. However, the Carriers' admit that their accounting records for SR do not separate the costs of automation from other SR costs. *Id* at 227. *See also* Ex. SOA-387; SOA-279 at 5. The Carriers tracked SR over a wide range of AFEs. Ex. AT-493. In addition, they argue that hybrid would have had the same growth as electrification. Carriers IB 228. As discussed above, the Carriers have not showed that the automation costs were prudently incurred. Anadarko points out that it is less likely that the Carriers would have mismanaged Hybrid and since it was assumed to be a brownfield project from the start it is less likely they would have underestimated the costs of Hybrid to begin with. The Carriers arguments, as concluded above, are not persuasive.

1442. The Carriers also argue that cost disallowance would discourage investments in TAPS. Carriers IB 216. This argument is also without merit. The prudence test requires that the decision maker look at whether the costs are what a reasonable utility manager would have made in good faith, under the same circumstances, and at the relevant point in time. This decision follows this principle. This determination focuses on whether the rates are just and reasonable. The evidence in this case shows that the Carriers sanctioned SR based on inadequate study and economics, then they staffed the project with an inexperienced management team and contractors who lacked Alaska expertise or knowledge. They did not follow normal Alyeska procedures and safe-guards for projects. Within a year from sanction BP's President Bolea considered the project a "train-wreck" yet they pushed for approval of another $168 million for Supplement 2 in order to preserve the production's affiliate's booking of 63 million barrels of additional reserves.[692] Tr. 3705:24; 4148:12-4150:22. The Carriers' documents show that owner misalignments and affiliate upstream interests are a problem in managing TAPS and were drivers of SR mismanagement. Ex. SOA-375 at 2; AT-10 at 3; AT-19 at 6-7.

1443. The Carriers allegations concerning Anadarko's remedy formulations are without merit. Anadarko's remedies are consistent with the evidence in this case and case law.

[692] Again with no current ratepayer benefit.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Remedy 2 gives the Carriers the benefit of the doubt on their initial sanction decision even though the evidence in this case supports the finding that at that point in time the economics of SR were indeed dubious.[693] The remedy is a ceiling on ratepayer benefits and utility of the project. As Anadarko points out, since AFE S020 was approved the SR costs have tripled and are still growing, however, the Carriers have never argued that ratepayers' benefits have increased along with costs. Remedy 3, is based on record evidence which shows that the Carriers should not have approved Supplement 2. These remedies are thus grounded on cost inclusion as opposed to exclusion which simplifies the remedies and resolves potential issues in the future such as the costs for PS 1 which was within the scope of AFE S020 and related AFEs. In response to the Carriers contentions about SIPPS Anadarko responds that its remedy number 1 contemplates recovery of over $17 million for SIPPS which Anadarko claims is charitable since SIPPS was mismanaged and not reliable. Anadarko's RB 132. Anadarko also responds that the same charitable approach is not possible for the SCADA system since this was badly mismanaged, has multiplied the number of alarms, threatened reliability, and increased shutdowns. Anadarko's RB 132. The evidence in this case supports Anadarko's disallowance of the control systems upgrade, under the various theories, prudence, not use and useful, provides no ratepayer benefit and has failed to achieve its goals.

1444. Anadarko is correct in starting its remedy calculations at $454.4 million or the total amount of SR capital costs included in the 2009 and 2010 rates. This is the total costs of AFE S020 and related AFEs which funded the SR project, including costs for electrification, SIPPS, control systems and other associated projects. Ex. SOA-55. For remedy 3 Anadarko used the numbers in AFE S020 and the Supplement 2 numbers. Ex. SOA-11 at 4. Anadarko is correct that modifying the proposed remedies as the Carriers' suggest would give them the benefit of recovering imprudent costs which were calculated in the basis used by Anadarko.[694] As Anadarko states its remedy 2 and 3 would allow the Carriers to recover costs up to a level commensurate with ratepayer benefits under assumptions favorable to the Carriers. Further, Anadarko is correct that the evidence in this case supports the finding that at Supplement 2 SR was off track, original cost estimates were wrong, the scope was not defined, contractors were not performing, and the economics were not favorable. For instance, Exxon found that the project had a negative net present value at this point. Ex. ATC-27 at 50-51. Further the project was characterized as a train wreck. Ex. AT-252. However, the Carriers proceeded with the project. Anadarko is correct that proceeding beyond this point was imprudent and unreasonable. Finally, Anadarko asserts that the Carriers are incorrect since its remedy 4

[693] SR was "really a marginal economic project, a couple million dollars of capital investment. And at $750 million, there is no benefit. It's just a huge rate increase with no benefit to ratepayers, because they get basically the exact service they had before." Tr. 234:15-20 (second phase).

[694] Carriers IB 247.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

only includes electrification costs or isolation of the costs of electrification based on Dr. Toof's analysis. Anadarko's RB 135.

1445. Since TAPS is a monopoly pipeline, there are no competitive alternatives. Under this scenario, the integrated economics of the conglomerates that own TAPS, incentivizes the production affiliate to ship on its affiliated Carrier, regardless of whether its affiliate has the lowest tariff. As a result, the shipping of oil on TAPS occurs thorough pocket-to-pocket transactions between affiliated producers and Carriers, which has no economic significance within the integrated companies. Tr. 4891:3-7; 4900:15-25. As a result, the economic benefit of including SR costs in the tariff flows to the Carriers production affiliates in the form of lower taxes and lower royalties paid to the State.

1446. The Carriers disallowance methodology lacks merit. The Carriers posit that the total disallowance should be $53.6 million. Carriers IB 248-55. However, Anadarko and the State are correct that the Carriers' should not recover costs for imprudent behavior and thus they should not be allowed to recover the cost of adopting a sequential schedule, for correcting contractor errors, newly identified work and "productivity losses." Carriers IB 252-53. Ratepayers should not bear additional costs to correct problems that were caused in the first instance by the imprudence of the Carriers' or their mismanagement. The evidence shows that the Carriers proceeded on an unattainable fast-track schedule, the project economics were based on attaining the schedule and the Carriers' missed the true scope of SR. Carrier witness Dr Toof agreed that "[t]o the extent that the costs grew because of mismanagement deficiencies, then I think they should be held accountable for that." Tr. 6178:25-6179:2.

1447. Likewise, since TAPS is the only means of moving ANS production to market, independent producers have a compelling interest in TAPS regulation and cost control. Higher tariff rates as a result of imprudent actions would only serve the interests of the owners of TAPS. Independent producers are also concerned that the TAPS rates are inflated by uneconomic and operationally unjustified project costs. This is a consequence of the statements in the 2009 Scoping White Paper, Ex. SOA-574 at 5, which shows that the Carriers decided to move forward with SR on PS 1 because canceling the project would require the Owners to expense up to $91 MM and none of the write-off would be allowed in the tariff. The document also shows that the Carriers continued with PS 1 electrification to avoid writing off the sunk costs even though the SR equipment is not optimal for current TAPS needs and could raise air-quality issues.[695] Ex. SOA-574 at 7. Moreover, the SR cost overruns if not modified by regulators will result in large rewards to the Carriers' in the form of higher returns and income taxes, since return and income taxes are based on the size of the rate base. Anadarko is correct that it is unfair to require

[695] Anadarko is correct that it is ironic that the Siemens TGs are oversized, since the Carriers argue that the legacy equipment had to be replaced because it was too powerful. Carriers IB 59-60.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

TAPS ratepayers to pay the Carriers additional return and taxes due to the inflated costs of a poorly planned and managed project.[696]

1448. Staff avers that Commission and court precedent accord the Commission broad discretion in fashioning remedies in this situation. Staff urges that the hybrid option be adopted as a remedy since it is persuasive. Under this option the Carriers would not have replaced the existing equipment and simply upgraded and automated the existing control systems. Thus, all costs above the prudent option- the hybrid option- would be disallowed (a total disallowance of $393.8 million as proposed by State witness Adams and adjustments recommended by State witness T. Horst). However, this amount should be offset by the SCADA and SIPPS costs. According to Staff, if industry standards had been followed this would have been the option selected since this option provided the same benefits.

1449. Staff also argues that Grasso's proposal to remove costs solely attributable to electrification (the imprudent option) and allowing the remaining costs (the prudent expenditures) has merit as a basis for a further remedy or the removal of costs that are not used and useful to the shippers. Staff argues that it is difficult to isolate and identify all costs associated with the SR project and electrification but it is possible to determine reasonable cost figures for both of these items. This is a reasonable remedy supported by the record for a total disallowance of $389 million. As to SCADA, Staff avers that the Carriers have failed to prove that it is used and useful, and the costs should not be included in rate base. Finally, Staff argues that a third remedy for the imprudence would be to disallow all costs after the point in time when the Carriers themselves acknowledged that the project was a "train wreck" or November 2005, when the Carriers adopted supplement 2. Given that the Carriers had recognized that the project was in serious trouble it was indisputably imprudent for the Carriers to continue to incur costs in pursuit of the SR project after this point in time. Thus, the post-November 2005 costs of the SR project, which exceed the $266.42 million spent up to that point, should be excluded from rate base. According to Staff, this is also a reasonable remedy.

1450. Staff also suggests that additional alternative remedies are possible if a decision is made that the Carriers were prudent or if a determination is made that additional cost disallowance is needed under alternative theories. The cost disallowance (or additional disallowance) would be based on a finding that the new infrastructure installed under SR is not "used and useful" and does not provide "ratepayer benefits" of fails the "intergenerational equity" test. Under this, Staff recommends, the remedy advanced by Grasso based on removing the capital cost additions attributable solely to electrification from the total additions to property in service for the rate years at issue in this proceeding. This recognizes that electrification costs are not "used and useful" and do not provide benefits to current ratepayers.

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[696] Anadarko's RB 128 citing Tr. 4302:10-15 and 4305:10-18.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Discussion

1451. The preponderance of the evidence in this case shows that the Carriers were imprudent in the development, design, implementation and management or execution of the project. As Staff points out, the early studies showed that the only upgrades to the TAPS infrastructure needed to maintain TAPS as a "world class" pipeline and to assure TAPS "operational excellence" were to the control and telecommunications systems. The early studies did not recommend replacing the legacy equipment. Indeed, the studies found that the legacy pumps "are essentially infinite life, there are no obsolescence issues." However, despite these findings the owners decided to incur hundreds of millions of dollars of unnecessary costs associated with removing the legacy pumps and replacing them with electric pumps. The Carriers did not follow industry standards in preliminary engineering and consequently did not do sufficient FEL at the time they started the project. As a result, the scope was ill defined, there was no MOC and the fast tracking of the project did not allow the scope to be defined in an adequate manner. In December 2006 the Carriers analyzed what was wrong with the project. They took certain steps such as, selecting Alyeska as the project manager, they changed the schedule and they became enlightened to the fact that they should electrify the pump stations one at a time. There is no evidence in this record that at this point in time they stopped to declare a train wreck. As a result, the project continued to be plagued by the imprudent actions taken before. Significant number of drawings had to be redone, funding was insufficient and they had to keep coming up with new estimates. Cost overruns were increasing. To this date PS 1 is not complete and the SCADA system is substandard.

1452. At the particular point in time when they had to delay the project beyond the end of 2005 the economic drivers for the project were gone. In 2006, fire upgrades to the buildings had to be made, that was one incentive for the project that was gone and the project was postponed to 2007 so the other economic incentives were gone. The bonus depreciation tax benefit, one of the drivers of the schedule, expired at the end of 2005. Ex. SOA-292 at 3. When Exxon evaluated the project economics at Supplement 2 it added $10 million as a "special cost and schedule allowance" and determined that SR had a negative net present value. Ex. ATC-27 at 50-51. At this point in time they should have stopped and analyzed the economics of the project and they did not. This was not the action of a reasonable utility manager.

1453. SR was a discretionary project with the purpose of reducing costs.[697] The Carrier's failure to perform adequate engineering to correctly ascertain the scope of SR and thus the cost of the project was imprudent. Tudor and Toof suggested that SR cost what it was going to cost, the implication being that not having a good handle on costs before starting the project did not make it imprudent. Tr. 5076:19-5078:2 and 6065:25-6066:17. However, a project driven by cost savings requires an extremely accurate

[697] Tr. 4604:8-12; 4779:16-17; Ex. ATC-18 at 12.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

understanding of costs before a company proceeds to execute the project. The Carriers chose to accelerate the project in order to achieve the cost reductions sooner.[698] Thus, they assumed the risks that their projections were incorrect since they did not take the time to comply with industry standards. They missed essential scope, consequently costs increased, delays occurred and equipment issues arose resulting in no additional ratepayer benefit or utility over the legacy equipment. It was also imprudent for the Carriers to decide that the project could be completed in two years. Earlier studies had concluded that automation alone would take 4 to 5 years, so the Carriers assumption that both automation and electrification could be completed in two years was not consistent with a reasonable utility manager. Ex. ATC-119 at 2. Anadarko is correct that the Carriers adopted a tight schedule which required "flawless execution" and "no tolerance for delays" to make weak economics look plausible. Ex. SOA-324; SOA-197 at 9, ATC-24 at 37 and SOA-232 at 7; SOA-292 at 3; Tr. 4788.

1454. The Carriers knew that there were misalignments issues that would impact the project and introduced upstream concerns into SR and delayed the schedule. Moreover, they also knew that creating a management team outside Alyeska operations would complicate the effort to achieve the aggressive schedule. Tr. 3447:5-10. As D. Hisey testified the problem was "putting in place a brand-new team that's unfamiliar with Alyeska, unfamiliar with Alaska, unfamiliar with the assets that they are going to have to tie in to, and thinking that you can pull it off in two years in a flawless manner." Tr. 3448:2-6. The Carriers also knew that after years of study Alyeska had never recommended electrification. Tr. 2962:13-21. Alyeska had only considered electrification as a pilot project at PS9, which was the only PS close to a commercial grid. Ex. ATC-105 at 14-15. The Carriers imprudently assumed the risks of this project and should be held responsible for them.

1455. The project was ill conceived (electrifying pump stations with no commercial power grid), rushed (benefits based on an impossible schedule), and poorly managed (bad cost/benefit estimates, missed scope, inadequate project team, owner misalignment and upstream affiliate concerns). Exs. SOA-233 at 2-4; SOA-453 at 1-2; SOA-183 and Tr. 4933:3-4934:12. Thus, the costs of SR should be borne by shareholders and not ratepayers. While BP executives were stating that SR was a "train wreck" and "performance bust," they were advocating that the project continue because BPXA, the production affiliate, had booked 63 million barrels of oil based on the SR project.

1456. Anadarko and the State have established by preponderance of the evidence including expert testimony what the industry standard is for developing and managing such a project. This evidence proves that the TAPS Owners repeatedly failed to meet industry standards for developing and managing the project. For example: they failed to adequately review the condition of the existing (legacy) natural gas and liquid fueled

[698] Ex. ATC-24. Carriers IB 138.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

turbines (the preponderance of the evidence in this record shows that the legacy turbines were operating reliably and efficiently and did not need to be replaced); they failed to determine if the legacy equipment could be modified to achieve the benefits that allegedly could only be achieved through replacing the legacy equipment with electric pumps; the Carriers imprudently selected the electrification over the hybrid alternative (retaining the legacy equipment and only upgrading and automating the pump station control and data systems); they failed to conduct reasonable preliminary engineering and FEL for the project; they failed to properly determine the regulatory requirements for the SR project; they failed to determine the availability of electric power at PS 9 and 1; and they failed to properly select and supervise their contractors.

1457. The Carriers own documents and emails shed light on their imprudent decision-making. For instance, they admitted that proceeding with SR "without the benefit of preliminary and final engineering" was a "fatal flaw;" they were told that "design engineering was not complete" but nevertheless they ordered the project to proceed; the project was sanctioned well before the necessary and critical engineering and other preparatory work had been done because of "tax advantages to have the project completed by December 31, 2005; "cost estimating" was "deficient;" the "costs control system was not robust enough given the size of the project;" "the design given to the fabricators was bad and incomplete;" "there were approximately 12,800 drawings revised which is unacceptable;" "the SR management team was understaffed;" an engineering procurement construction and management firm (EPCM) with "proven Alaska track record" should have been selected to manage the SR project;" a "much higher level of Front End Loading" should have been done."

1458. The Carriers' imprudence resulted in hundreds of millions of dollars of unnecessary costs. The Carriers are attempting to recover these costs from their ratepayers. Since the costs were imprudent, the recovery of these costs should not be allowed. Based on the above, and as argued by Anadarko its remedy number 3 seems to be a reasonable remedy in this case. At supplement 2 the Carriers knew the project was a "train wreck." Costs had nearly doubled, the schedule could not be accomplished, contractors were underperforming, the owners were failing to make timely decisions, engineering delays, design issues, revision of drawings, unproven pump motors, the scope of the project was not well defined (the project scope was not fully established until well into detailed design) significant brownfield work, inadequate cost accounting. The Carriers knew that the original cost estimates were wrong. The benefits were eroded once the schedule had to be changed. Therefore, supplement 2 costs and forward will not be included in rate base. The Carriers will be allowed to flow through rates the original AFE S020 costs and supplement 1, totaling $229.2 million to be amortized over the remaining life of the pipeline. For the filed 2009 and 2010 the rate base exclusion is $225.2 million. Under this remedy future costs of PS 1 would not flow through rates since the original AFE SO20 included PS1, thus avoiding any additional prudence

20140227-3052 FERC PDF (Unofficial) 02/27/2014

litigation for SR.[699] The costs for supplement 2 and forward are deemed costs which a reasonable utility management would not have made in good faith, under the same circumstances and at this point in time.

1459. The costs allowed in rate base are a remedy in equity since those costs are also considered imprudent. Elimination of all costs from rate base was seriously considered and rejected as too harsh a remedy. In the purest sense of the precedent if the conceptualization of the project was imprudent then one could argue you cannot cure an imprudent act because the concept was flawed to begin with. However, since there are new assets in the ground it seems reasonable to let the Carriers recover some of the costs.

1460. The option to recover just for automation was considered and rejected since a careful review of the record in this proceeding shows that even though Bailey had recommended automation improvements the Carriers did not implement the Bailey recommendations. The evidence in this case shows that the Carriers automated in an imprudent manner, waiting years before they started studying the issue while they were electrifying the pumps and then what was developed is substandard. Consequently, this option was rejected.

1461. The States' recommendation to consider the difference between the costs for hybrid and electrification is rejected based on the fact that this decision finds that the costs of hybrid are not supported by any evidence in this record. Even the Carriers note that in 2002 the costs for hybrid were rougher than electrification (-15%/+50%) (with a bias towards increasing costs since the costs for hybrid did not receive the "same degree of engineering review for the scope of work"). Ex. ATC-154 at 41; Carriers RB 133. In 2003, the hybrid estimate had not been developed to the same level of accuracy as the electrification estimate: the hybrid estimate was within +/-30% (Ex. SOA-163 at 4) and the electrification estimate was +/- 15% (Ex. ATC-208 at 8). Consequently, no value is given to these numbers even for remedy purposes. As a result of the decision finding the

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[699] Although cognizant of *Minn. Power & Light Co.*, 43 FERC ¶ 61,104 at 61,343 (1988) (inquiry as to prudence of utility decision should occur at time the company actually seeks to reflect the effect of the proposed transaction in rates), the determination as to PS 1 has to be done at different stages. First, PS 1 was part of the original flawed design. Thus, it was intertwined in the original project and any determination of prudence at that point in time must include PS 1. Second, they could have stopped PS 1 and chose not to for purely affiliate reasons. Third, this determination avoids relitigation of the costs in this decision. Moreover, the true costs of SR will never be really known. The record shows that the third party vendors were not keeping good accounting of costs and the Carriers have not come forward to prove that their filed rates do not include any PS 1 costs. At the time the project started they were constructing all the pump stations at the same time with poor cost tracking. The Carriers have failed to show that PS 1 costs are not included in the filed rate. Consequently, this decision captures this anomaly.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

project imprudent, the States' alternative remedy is moot (disallowance for execution). However, were an appellate body to find that the project was not imprudent the State's alternative remedy methodology is deemed accurate.

1462. Concerning the costs of F370 the SCADA HOST replacement the evidence in the record shows that the Carriers did not design an adequate alarm system. This was the result of deferring the engineering of this system compounded with the fast track schedule. Consequently, they cannot recover the costs imprudently incurred for the controls and alarm system or money spent under F370. *See* Ex. SOA-387 at 4.

1463. The Carriers argue that if the State and Anadarko prevail, this would require decisions that are unprecedented in FERC's history, because it requires rejection of the extensive justification for the SR project at sanction and dismissal of the judgment of individuals who have worked at TAPS for over 25 years. Regretfully, this is one of the very few arguments that the Carriers make which has any merit. Analysis of the evidence in this record shows that the sanctioning and execution of the project was not done in accordance with industry practice and as a reasonable utility manager would have done under the same circumstances with the facts that they knew or should have known. Giving the Carriers the benefit of the doubt and agreeing with the fact that they have "broad discretion" and "considerable latitude" in conducting the business of TAPS, that the decisions of management cannot be second-guessed based on later occurrences and that their decisions cannot be replaced based on hindsight, based on the preponderance of the evidence in this record, the decision reached is still the same, they acted imprudently. This decision is based on the facts known at the time and it is concluded that this was not just a merely "flawed or even wrong-decision making." Owners take risks yes, but owners of utilities (transportation of petroleum products) cannot take the same risks as the owners of exploration and production. As a matter of fact the Commission routinely removes the production parents from the capital structure of the pipelines due to the production parent's high risk profile in setting rates for pipelines. *See BP Pipelines (Alaska) Inc.*, 113 FERC ¶ 63,007 at P 189 (2007) *aff'd in part* 123 FERC ¶ 61,287 P 177 (2008). In this case we are dealing with the regulated utility. The production/exploration owners are the ones who can afford to work on a vision instead of a plan.

1464. The Carriers are correct that a utility manager is given ample discretion in the case law. However, discretion is not limitless. A regulated utility has to act in a reasonable manner. A reasonable utility manager faced with a depreciated asset could have sought advice from this Commission on what measures could be undertaken to remedy that situation.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

iv. Disallowance underUsed and Useful and Other Ratemaking Principles

1. Used and Useful

1465. Should the Commission disagree with the prudence findings above, a determination that the SR project was not used and useful provides a separate and independent ground for excluding SR costs from rate base. Anadarko and Staff argue that the SR project is not used and useful, and its costs should be excluded from rates.[700] While the Carriers do not suggest that used and useful is inapplicable in this case, they disagree with Anadarko and Staff as to its formulation and application and assert that used and useful (and other ratemaking principles discussed below) "should clearly be applied sparingly and with great care." Carriers IB 197.

Findings/Discussion

1466. The Commission has consistently required an investment to be used and useful in providing service[701] **f**or its costs to be included in rate base.[702] Current ratepayers should bear only the cost incurred in providing service to them.[703] While the prudence inquiry is focused on earlier decision-making, used and useful is evaluated at a later stage.[704]

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[700] Anadarko IB 14, 164-88; Staff IB 103-16. The State is silent on this issue.

[701] *Denver Stock Yard Co. v. United States*, 304 U.S. 470, 475 (1938) (A utility is not entitled to include in rates "any property not used and useful" for rendering services). *Tenn. Gas Pipeline Co. v. FERC*, 606 F.2d 1094, 1109, 1164 (D.C. Cir. 1979) ("an item may be included in a rate base only when it is 'used and useful' in providing service."). *United Gas Pipe Line Co*., 27 FERC ¶ 61,118, at 61,230 (1984) ("the long established Commission practice . . . requires a customer to pay for jurisdictional facilities only to the extent that those facilities remain 'used and useful.'").

[702] *Tenn. Gas Pipeline Co.*, 606 F.2d at 1123 ("for rate base inclusion expenditures must satisfy not only the necessary condition of prudent investment but also must be 'used and useful' in providing service"); *id*. at 1109 ("current rate payers should bear only legitimate costs of providing service to them."); *Williston Basin Interstate Pipeline Co.*, 48 FERC ¶ 61,137, at 61,538 (1989) ("a prudent investment by a public utility may not be used and useful to the ratepayer" and "only prudent investment for utility property which is used and useful to provide service to the utility's customers should be compensated.") (citing *New England Power Co.*, 42 FERC ¶ 61,016, at 61,078 (1988)).

[703] *New England Power Co.*, 42 FERC at 61, 078.

[704] *Williston Basin Interstate Pipeline Co.*, 48 FERC ¶ 61,137, at 61,538 (1989) ("The prudence rule looks to the time of investment, whereas the used and useful rule

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Prudent decision-making does not necessarily yield a used and useful result. Thus, applying both standards helps ensure rates are just and reasonable by disincentivizing subsequent mismanagement of an initially prudent investment and neutralizing the incentive to unnecessarily augment capital in order to include it in rate base after the prudent investment decision was made. *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1190 (D.C. Cir. 1987) (Starr, J., concurring) (The "obvious danger in not examining both ends of the continuum -- both the prudence of the investment and whether the end result of the investment was used and useful – is to build in pressures for building excess generating capacity. The 'used and useful' rule operates as a restraining principle, reminding utility managers that they must assume the risk of economic forces working against an investment which is prudent at the time it is made.").[705]

1467. Examples of not used and useful investments include those that are unnecessary[706] or speculative and from which ratepayers do not benefit. A speculative project is one where shareholders stand to gain from the upside of the investment and thus should bear the downside risk (and related costs) as well. Thus, expenses that are "entrepreneurial in character" are not recoverable in rate base because allowing that would shift some of the downside risk from shareholders to ratepayers while preserving the upside for the shareholders who benefit from the rate of return. *Columbia Gas Transmission Corp.*, 13 FERC ¶ 61,102, at 61,222 (1980). ("The used and useful principle does not permit the pipeline to shift the risk of loss [from the stockholder to the ratepayer] by imposing the expense of the unsuccessful project upon its current ratepayers who have received no benefit from the project"); *Natural Gas Pipeline Co. of Am.*, 27 FERC ¶ 61,201, at 61,379 (disallowing costs for three abandoned gas supply projects, where the costs (proposed to be amortized over five years) were "found to be speculative and uncertain, remote in time, and without benefit to ratepayers. These projects have been held to constitute risks which should properly be borne by shareholders rather than ratepayers

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looks toward a later time."). *Natural Gas Pipeline Co. of Am. v. FERC*, 765 F.2d 1155, 1157, 1163-4 (D.C. Cir. 1985).

[705] *See also Williston Basin*, 48 FERC at 61,537 ("Requiring an investment to be prudent when made is one safeguard imposed by regulatory authorities upon the regulated business for benefit of ratepayers. . . . [T]he 'used and useful' rule is but another such safeguard. The prudence rule looks to the time of investment, whereas the 'used and useful' rule looks toward a later time. The two principles are designed to assure that the ratepayers . . . will not necessarily be saddled with the results of management's defalcations or mistakes, or as a matter of simple justice, be required to pay for that which provides the ratepayers with no discernible benefit.") (citation omitted).

[706] *Williston Basin*, 48 FERC ¶ 61,137, at 61,539-40 (purchasing gas and storing it was prudent but not used and useful because it was not necessary to ensure delivery).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

and which should be compensated by means of the pipeline's allowed rate of return rather than by means of a specific allowance in the cost of service.") (citation omitted).[707]

1468. While certain public interest considerations may except prudent investments from the used and useful standard, none of them apply here. In certain instances, the Commission has excepted some construction work in progress (CWIP) costs, because a literal interpretation of the used and useful principle would foreclose allowing any CWIP in rate base under any circumstances.[708] The Commission has also excepted certain research and development costs[709] and may also depart to some extent from the used and useful standard "when the reliability of future service is in doubt."[710] Public interest exceptions are discussed in *Mid-Tex Elec. Coop. v. FERC.* The Carriers cite *Mid-Tex Elec. Coop.* in an attempt to find support for "widely recognized exceptions and departures from [the used and useful] rule, particularly where there are countervailing public interest considerations."[711] But unlike the exceptions discussed in *Mid-Tex Elec. Coop.*, there is no widely recognized exception for the situation in the instant case to support a departure from the used and useful standard for SR. The Carriers have not

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[707] *Natural Gas Pipeline Co. of Am.*, 27 FERC ¶ 61,201, at 61,380 ("There is no evidence that Natural acted unreasonably . . . . While [its] actions [are justified] in a corporate business sense, it does not justify imposing all of the resulting losses on consumers. . . . To approve amortization here would result in a direct transfer of risk and related cost from Natural's shareholders to its ratepayers. It would require the ratepayers to bear the costs associated with this speculative project, from which they received no benefit.") (citation omitted); *Natural Gas Pipeline Co. of Am. v. FERC*, 765 F.2d 1155, 1163-64 (D.C. Cir. 1985) ("The Commission did not find that the disputed expenditures were imprudent," but that does not mean "ratepayers must, through the utility's cost of service, make good on all or any part of the money . . . lost.").

[708] *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327, 332 (D.C. Cir.1985) (citations omitted). But for gas pipeline rates *see Tenn. Gas Pipeline Co.*, 561 F.2d 955, 958 (D.C. Cir. 1977) ("Both historical practice and Commission regulations firmly establish the propriety of excluding CWIP from the underlying rate base.").

[709] *See, e.g., Tenn. Gas Pipeline Co.*, 606 F.2d at 1123.

[710] *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327, 332 (D.C. Cir.1985) (citations omitted).

[711] Carriers IB 199 n.109 citing *Mid-Tex Elec. Coop.*, 773 F.2d at 332.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

shown that the Commission should adopt a strict prudent investment standard without a used and useful component, as is their burden.[712]

1469. The Carriers' citation to *Jersey Central* does not support their arguments that the Commission should not apply the standard here. The Carriers cite to this case to say that the used and useful standard "need not be, and is not, employed in every instance."[713] While this may be true, the Carriers fail to analogize *Jersey Central* to the instant case to justify an exception here. In *Jersey Central*, a case involving nuclear plant abandonment, "federal and state agencies were encouraging utilities to commit substantial amounts of capital to nuclear generating plants that required lead times of eight to twelve years," and the consensus prediction was that demand for electricity was rising.[714] Further, the utilities invested in nuclear power because they were "under statutory obligations to plan and build facilities necessary to meet the projected needs of their customers."[715] As Anadarko points out, the facts in the instant case are not similar: SR was not undertaken to fulfill a legal obligation to meet future demand or in response to regulatory pressure. Instead, it is a discretionary project attempting to reduce TAPS costs. Anadarko RB 93.

1470. From a process perspective, *Jersey Central* also does not support restraining the Commission from applying the standard here. The *Jersey Central* court noted that judicial review of the Commission's decision is highly deferential, and only for a due process violation can courts intervene.[716] It did not second-guess the Commission

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[712] *See New England Power Co.*, 42 FERC ¶ 61,016, at 61,078 (1988) ("NEPCO has not shown that Commission policy should be changed to a strict prudent investment standard.").

[713] Carriers IB 198 (citing *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1175, 1183 (D.C. Cir. 1987)).

[714] *Jersey Cent.*, 810 F.2d at 1170-71.

[715] *Id.* at 1171.

[716] *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1175 (D.C. Cir. 1987) ("[W]ith the demise of "fair value," "used and useful" ceased to have any constitutional significance, and the Commission has at times departed from this standard. It is now simply one of several permissible tools of ratemaking, one that need not be, and is not, employed in every instance. In setting aside the rigorous judicial scrutiny that had previously characterized review of rate orders, the Supreme Court substituted a far more deferential standard of review: Once a fair hearing has been given, proper findings made and other statutory requirements satisfied, the courts cannot intervene in the absence of a clear showing that the limits of due process have been overstepped. If the Commission's order, as applied to the facts before it and reviewed in its entirety, produces no arbitrary result, our inquiry is at an end.") (citation omitted).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

application of the used and useful standard. Rather, the case was remanded for deficiency of process because Jersey Central was denied a hearing and its rates reduced summarily.[717] The court left it to the Commission to decide whether to apply the used and useful standard or some other ratemaking formula.[718] Unlike Jersey Central, the Carriers had ample opportunity to present their case in hearing.

1471. Similarly, contrary to the Carriers' contention (Carriers IB 206-07), the *Town of Norwood v. FERC* does not justify recovery here. In that case, the court upheld allowing cost recovery of "prudent but canceled investments" in a nuclear power plant that had since closed (and thus not used and useful).[719] But the recovery was justified from a cost-benefit perspective because "the plant had benefitted ratepayers by providing efficient service for 31 years, and that shutting down the plant would save ratepayers more than $100 million."[720] Further, "[d]enying full recovery would likely give investors an incentive to operate plants until they recouped all of their investment even though closing the plant would save ratepayers money."[721] This is not the fact pattern here as the actions undertaken in the SR project have not been shown to be cost-benefit justified (as discussed below).

1472. In addition, the record evidence shows that the Carriers' were likely motivated by improper incentives including the desire to build up a system that was fully depreciated and therefore did not contribute to rate base. This is precisely the type of activity used and useful is meant to prevent. Mismanagement of an otherwise prudent decision is another type of activity used and useful is supposed to guard against. Thus, from a policy point of view, the Carriers are not entitled to an exception.

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[717] *Jersey Cent.*, 810 F.2d at 1169-70 ("The decision of the Commission is vacated and the case remanded for a hearing at which Jersey Central may finally have its claim addressed.").

[718] *Jersey Cent.*, 810 F.2d at 1187-88 ("The Commission is not precluded from employing "used and useful," or any other specific rate-setting formula. It must ensure, however, that the resulting rate is just and reasonable. A remand will afford the Commission the opportunity to find the facts necessary" and "the Commission has the flexibility to determine how the rate order should be modified."). On remand, the ALJ disallowed the challenged costs. *Jersey Cent. Power & Light Co.*, 49 FERC ¶ 63,004 (1989); *Jersey Cent. Power & Light Co.*, 49 FERC ¶ 61,338 (1989).

[719] *Town of Norwood v. FERC*, 80 F.3d 526, 532 (D.C. Cir. 1996).

[720] *Id.* at 531.

[721] *Id.* at 532.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Burden of proof

1473. No participant disputes that the burden of proof is on the proponent of rates to demonstrate that the project is used and useful. The burden of proving that the project is used and useful is at all times on the pipeline filing for new rates, according to Staff.[722] Anadarko does not provide a general rule but asserts that the burden had already shifted in the prudence phase and is thus now on the Carriers. They reiterate the standard for the burden under prudence that the Carriers must come forth with specific evidence for each challenged cost item for the cost of service issues, but do not discuss a standard specific to used and useful. Anadarko IB 208. The Carriers do not discuss the burden of proof for used and useful.[723]

Discussion/Findings: Burden of proof

1474. The Carriers bear the burden of showing that the SR project is used and useful to the shippers in order to include SR costs in rates. This is not because the burden has shifted in the prudence determination, but because the proponent of the rates always bears the burden in the used and useful inquiry. If this were not the case, protestants unable to cast a serious doubt to shift the burden would lose the opportunity to bring a used and useful challenge.

1475. As discussed below, the Carriers have not met their burden of demonstrating that the SR project is used and useful. Instead of presenting the evidence and affirmatively justifying SR to be used and useful, the Carriers argue for a more lenient legal standard and only attempt to parry Anadarko's and Staff's claims. As with the prudence phase of the inquiry, it is important to emphasize that the Carriers possess the evidence and understanding of their accounting methods, they alone are positioned to deliver this information.

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[722] Staff IB 106-07 (citing *Consolidated Gas Supply Corp.*, 27 FERC ¶ 61,426 at 61,789 (1984) ("before Texas Eastern may seek to make such a recovery, it must prove that the facilities in question are used and useful to other customers"); *Williston Basin Interstate Pipeline Co.*, 48 FERC ¶ 61,137, at 61,539 (1989) (finding "that Williston has failed to establish that the volumes … were used and useful to Williston's customers.")). Under used and useful, "expenses may be recovered where it can be demonstrated that they contribute to the project." *Columbia Gas Transmission Corp.*, 13 FERC ¶ 61,102, at 61,222 (1980). This implicitly indicates that the proponent of including the expenses in the rate has the burden of demonstration.

[723] The Carriers contest whether they have the burden to show that the benefits of the SR project were commensurate with its costs, but this was about what the used and useful standard entails, and not who has the burden in showing that the project was used and useful. Carriers RB 119 n.151.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

The two-pronged used and useful test, usefulness determined by benefits commensurate with costs

1476. The parties and Staff do not dispute that an investment must be used *and* also useful to be included in rates (i.e., there are two prongs to the test).[724] However, the Carriers claim in a footnote that "the 'useful' prong of the standard is typically analyzed only when the asset at issue is not being used," so that the "'used and useful' standard can be satisfied when only a single prong of the test – *i.e.*, the 'useful' prong – is met."[725]

1477. Staff and Anadarko do not dispute that the SR investments at issue are used.[726] Note, however, that at pump station 1, some of the SR equipment that will be placed into service may not be used.[727] According to Anadarko, based on Alyeska's projections, "at current throughput levels (around 550,000 bpd), there will be 0 percent load placed on the new 12.9 MW Siemens Cyclone turbine" at PS 1. Anadarko RB 96 (citing Ex. SOA-574 at 19). If that is the case, the new Siemens will not be used. As a result, Anadarko argues that the Commission should not encourage the installation of unneeded upgrades at ratepayer expense.

1478. While participants generally agree that usefulness requires some form of ratepayer benefit, they construe the benefit requirement differently and disagree as to whether the useful prong of the standard may incorporate a weighing of costs and benefits.

1479. Anadarko and Staff disagree with the Carriers as to what types of benefits may be included in the useful analysis. Staff and Anadarko contend that "useful" is determined by comparing the intended benefits of the project (i.e., those stated upfront as a

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[724] Anadarko RB 94-95. The Carriers state that "for costs to be included in rates, a prudent investment must also be (1) "used," meaning placed into service, and (2) "useful," meaning that it is beneficial to ratepayers." Carriers IB 198 (citing to *Interstate Power Co*., 2 F.P.C. 71, 80 (1939) (stating that costs recovered by utilities must be connected to a facility "actually used in rendering service"); *Tenn. Gas Pipeline Co. v. FPC*, 561 F.2d 955, 957 (D.C. Cir. 1977) ("The Commission has a long-established ratemaking policy of charging construction costs only to those consumers who benefit from the new service.")). *Tenn. Gas Pipeline Co.*, 606 F.2d at 1109 ("rate payers should bear only legitimate costs of providing service to them").

[725] Carriers RB 122 n.153.

[726] Carriers IB 199 (asserting that there is no plausible argument that the SR facilities are not being used). Anadarko's analysis begins with whether SR is useful. Anadarko RB 96.

[727] The equipment at pump station 1 is not yet in service. Carriers IB 16.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

justification of the project) with the actual benefits realized by customers.[728] They assert that SR must be evaluated on financial and not operational usefulness to TAPS Shippers because cost savings and the attendant reduced rates were the drivers for the project.. Anadarko adds that useful investments must be necessary to pipeline operations and produce a net economic benefit for ratepayers. Anadarko IB 189-94. Staff states that the used and useful test requires the Carriers to prove that the SR project provides an enhanced level of service. Staff IB 108-09. At the other extreme, the Carriers assert that the "proper test of whether an investment is useful is whether it is providing benefits, broadly defined, to ratepayers." Carriers IB 200.

1480. Anadarko and Staff assert that used and useful requires the benefit to ratepayers to be commensurate with the costs passed on to them.[729] The Carriers assert that the Commission does not apply a cost-benefit analysis as an additional threshold for cost recovery under the used and useful standard, and cite to a policy statement concerning recovery of costs for the installation of electric smart grid upgrades.[730] They also cite to a case where a generator capable of producing reactive power was considered used and useful whether it was used at a given time.[731] As far as the Carriers are concerned, there is no cost-benefit component in the used and useful standard: the "SR facilities are being used to provide service and that service is useful to shippers. That is all that is required." Carriers RB 117.

1481. At any rate, Staff and Anadarko contend that SR achieved no benefits for ratepayers. Anadarko states that the rate increased with no benefit to ratepayers. Anadarko IB 205; Anadarko RB 97; Tr. 234:15-20 (B. Sullivan). Staff asserts that SR "has not produced a scintilla of benefit" to independent shippers, and thus the Carriers have not shown SR to be used and useful. Staff IB 110.

1482. Carriers assert that regulators have applied the used and useful doctrine in a flexible manner that gives weight to benefits anticipated in the future or for investments that were useful to ratepayers in the past, but were no longer because either the benefits were temporary or regulatory policy changed. Carriers IB 205-06. In support of their contention that regulators have allowed recovery of investments not yet providing benefits but will in the future, Carriers cite to cases related to research and development and loans or advances to secure new gas supplies. Carriers IB 206 (citing *Process Gas*,

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[728] Staff IB 107, 110-11; Anadarko RB 96-97.

[729] Anadarko IB 164-71; Staff IB 103-10.

[730] Carriers IB 202; RB 117 (asserting that the used and useful standard has no cost-benefit component).

[731] Carriers IB 202 (citing *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282, at P 28 (2006), *order on reh'g*, 119 FERC ¶ 61,177 (2007)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

866 F.2d at 476 ("These cases confirm that "it is proper for [regulators] to charge existing ratepayers with costs of a project, the benefits of which all future ratepayers will enjoy.")). Carriers also cite to *Town of Norwood*, where costs associated with investments in a nuclear power plant could be recovered even though the plant had since closed) recovery was warranted in that case because the investments were "capital improvements in the structure of the plant – replacing worn plant components and improving the plant's efficiency" to "assure that an already used and useful plant could continue to be used and useful." Carriers IB 206-07 (citing *Town of Norwood* at 532).

Discussion/Findings

1483. As its name implies, the used and useful test has two parts: the investment must be used,[732] and it must also be useful (e.g. beneficial to ratepayers). *See Tenn. Gas Pipeline Co. v. FPC*, 561 F.2d 955, 957 (D.C. Cir. 1977) ("The Commission has a long-established ratemaking policy of charging construction costs only to those consumers who benefit from the new service. This policy rests upon the 'used and useful' test."); *Jersey Cent. Power & Light Co.*, 810 F.2d at 1190-91 (Prudence and used and useful "are designed to assure that the ratepayers . . . will not necessarily be saddled with the results of management's defalcations or mistakes, or . . . be required to pay for that which provides the ratepayers with no discernible benefit.") (Starr, J., concurring).

[732] *E.g.*, *Interstate Power Co.*, 2 F.P.C. 71, 80 (1939) (The property must be "actually used in rendering service").

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1484. The Carriers' cite to *SFPP*,[733] noting that the pipeline failed to show that the excess capacity was used, and claim that the useful prong is typically analyzed only when the asset at issue is not being used to provide current service so that the used and useful standard can be satisfied when only the useful prong is met.[734] This claim, together with the Carriers' interpretation that any benefit broadly defined can satisfy the useful prong practically guts the test's utility. This would almost be tantamount to only requiring that an asset is merely constructed and placed into service.[735]

1485. The used and useful test must include some assessment of benefits against costs. The Carriers assertion that the used and useful standard only requires that the SR facilities are used to provide service, and that service is useful to shippers (Carriers RB 117), without anything more, is tautological. Supplementing this statement with "useful" to mean any benefit broadly defined does little more. Further, without examining benefits in relation to costs, a pipeline could spend a fortune on a de minimis benefit and still pass the used and useful test.[736] This cannot be an appropriate articulation of a test that is meant to ensure just and reasonable rates. While the Carriers are correct to point

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[733] *SFPP, L.P.*, 116 FERC ¶ 63,059 (2006). While an initial decision by an Administrative Law Judge is not binding in this case, it does offer an example of how the two prongs of the test are distinct. In *SFPP, L.P.*, a twenty-inch diameter replacement segment to a pipeline was constructed when fourteen inches would have sufficed. The additional capacity could not have been used because the pipe was not similarly expanded elsewhere. *Id*. P 24 ("expanding the Concord-Sacramento segment's capacity from 14" to 20" did not increase the North Line's interstate capacity because SFPP did not expand the capacity of any other North Line segment east of Sacramento"). Thus the expansion was deemed not used. *Id.* PP 23, 28. This alone was found to be enough to preclude recovery even though it was separately found that the excess capacity was not useful, and that probable future cost savings and decreased major maintenance to be too prospective and speculative to be deemed useful. *Id*. P 26. "[B]oth prongs of the 'used and useful' standard must be satisfied . . . the expansion capacity fails the 'useful' prong as well . . . for the reasons stated in P 26, *supra*." *Id.* P 28 n.14 *See also* Jonathan A. Lesser, The Used and Useful Test: Implications for a Restructured Electric Industry, 23 Energy L. J. 349, 352 (2002) (citing *Denver Union Stockyard Co. v. United States*, 304 U.S. 470 (1938) (interpreting the difference as "investments that do not provide physical services (not used) and those that, while providing physical services, are superfluous (not useful))).

[734] Carriers RB 122 n.153.

[735] This was noted in *SFPP, L.P.* to be insufficient. *SFPP, L.P.*, 116 FERC ¶ 63,059 at P 23.

[736] Anadarko IB 171.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

out that a cost-benefit analysis is undertaken under the prudence determination,[737] assessing the benefits against the costs, as appropriate, to determine usefulness is necessary to preserve the utility of the used and useful standard. The two analyses are also different in that the economic analysis conducted at the time of sanctioning SR was whether it was economically justified (this is relevant to the prudence inquiry). Whereas, whether benefits *actually accrued* to ratepayers in a way commensurate to costs is relevant to the used and useful inquiry.

1486. Requiring benefits to be roughly commensurate with costs is consistent with Commission precedent. That costs must be legitimate in relation to benefits is apparent in *Tennessee Gas*: "an item may be included in a rate base only when it is 'used and useful' in providing service. In other words, current rate payers should bear only legitimate costs of providing service to them."[738] The Commission reiterated this same proposition in *Williston Basin* "that the rate base [should only contain] the actual legitimate cost of . . . property used and useful in furnishing the service." *Williston Basin*, 48 FERC ¶ 61,137 at 61,538 (citation omitted).

1487. Similarly, other cases discussing benefits to ratepayers also require that the Commission take into account benefits and costs to ensure that rates are just and reasonable. The Commission "need not engage in painstaking cost-benefit analysis . . . . Rather, the Commission is required to make only a candid, common-sense assessment as to the consistency of a project's objectives with the interests of the ratepayers providing the financing. FERC's mandate to determine 'just and reasonable' rates requires no less." *Process Gas Consumers Group v. FERC*, 866 F.2d 470, 477 (D.C. Cir. 1989).[739] This analysis includes "comparing the costs assessed against a party to the . . . benefits drawn by that party" and ensuring that customers "deriv[ing] no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members" are not fully responsible for these costs. *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (citing *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004); *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346-47 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 4-5 (D.C. Cir. 2002)). *See also Natural Gas Pipeline Co. of Am.*, 27 FERC ¶ 61,201, at 61,380 ("It would require the ratepayers to bear the costs associated with this speculative project, from which they received no benefit and from which they might not have benefited even if the project had been successful.").

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[737] Carriers IB 201.

[738] *Tenn. Gas Pipeline Co. v. FERC*, 606 F.A2d 1094, 1109 (D.C. Cir. 1979)).

[739] While *Process Gas* was not decided under used and useful, the court does discuss the Commission's practice of limiting rate base to used and useful items, and that ensuring just and reasonable rates requires such an assessment. *See Process Gas*, 866 F.2d at 476-77.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1488. The Carriers' citations to CWIP and smart grid policy statements[740] to oppose using cost-benefit analysis are inapposite. As Anadarko points out (Anadarko RB 100 n.572), the Commission does not state in *Smart Grid Policy* that an evaluation of costs and benefits is not part of the used and useful test. Rather, the Commission stated that its Smart Grid policy was consistent with the used and useful principle and the additional showings supplemented, but did not replace, the Commission's existing ratemaking standards. *Id*. P 127. The Commission merely stated that a formal cost-benefit or cost-effectiveness analysis should not be required as a filing requirement. *Id.* P 129. *Smart Grid Policy* is therefore inapposite to SR. Also, *Smart Grid Policy* was a response to a Congressional directive in the Energy Independence and Security Act of 2007. *Id.* P 2. SR did not implement any such directive.

1489. Similarly, the Carriers' citation to *Calpine Oneta Power, L.P*. does not support their position that cost-benefit analysis is confined to the prudence determination. Carriers IB 202. *Calpine Oneta Power, L.P.* dealt with reactive power, an ancillary service provided by an electric generator, *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282, at P 4 (2006), needed to maintain safety and reliability of an electric grid. Generators are considered used and useful if they are capable of providing reactive power regardless of whether such power is required at all times, because facilities that are in place for contingencies are still used and useful even if they are not always running. *See id.* P 28 (citing *Midwest Indep. Transmission Sys. Operator, Inc*., 114 FERC ¶ 61,192, at P 19 (2006)).

1490. To be relevant to usefulness, the benefit must be "discernible" – there must be some net or incremental benefit as compared to the service provided before the project. *Williston Basin*, 48 FERC ¶ 61,137 at 61,537-61,538 ("The used and useful standard . . . ensures that the ratepayers will not be required to pay for that which provides the ratepayers with no discernible benefit."). Further, the benefit must be direct and provided to current ratepayers. *Id.* at 61,538 ("to be included in the rate base, the costs . . . must be found to be prudently incurred (as has been found above), and must also be used and useful to Williston's rate payers in that they provide a direct benefit to its current ratepayers.").[741]

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[740] *Constr. Work in Progress for Pub. Util.; Inclusion of Costs in Rate Base*, Order No. 298, 1982-1985 FERC Stats. & Regs., Regs. Preambles ¶ 30,455, *order on reh'g*, Order No. 298-A, 1982-1985 FERC Stats. & Regs., Regs. Preambles ¶ 30,500, *order on reh'g*, Order No. 298-B, 1982-1985 FERC Stats. & Regs., Regs. Preambles ¶ 30,524 (1983); *18 C.F.R. Ch. I Smart Grid Policy, Policy Statement*, 128 FERC ¶ 61,060 (2009).

[741] *See also Natural Gas Pipeline Co. of Am.*, 27 FERC ¶ 61,201, at 61,379 ("these costs have been disallowed because the projects were found to be speculative and uncertain, remote in time, and without benefit to ratepayers."). The quoted text is in

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1491. The Carriers' test for useful is too broad; they assert the "proper test of whether an investment is useful is whether it is providing benefits, broadly defined, to ratepayers." Carriers IB 200 n.110. But the sources cited by the Carriers do not support a "broad" consideration of benefits. The Carriers cite to *Tenn. Gas Pipeline*, where the D.C. Circuit stated that "[t]he Commission has a long-established ratemaking policy of charging construction costs *only* to those consumers who benefit from the new service."[742] But this does not clarify which benefits help determine usefulness and certainly does not imply these benefits should be broadly defined. Similarly, the Carriers' citation to *Process Gas* does not support a "broad" consideration of benefits. There, the court noted that "[research, development and demonstration (RD & D)] financing is one of those unusual settings in which it is appropriate for FERC to authorize "the charging to current ratepayers of expenditures incurred by a jurisdictional company" even though the fruits of those expenditures may flow to future ratepayers."[743] But this is relevant to the "unusual" situation of RD & D financing, and whether future benefits may be accounted in usefulness (as discussed below), and not whether benefits should be broadly defined.

1492. There is no indication from the cases cited by the Carriers that the "benefits" should be broadly defined. Our precedent indicates that the benefits to be accounted are those that are discernible and directly benefit current ratepayers. While limiting benefits to those articulated as justification for the project provide a bright-line rule and prevents abuse by excluding frivolous benefits, allowing for certain secondary benefits provides flexibility needed to adapt a project as it progresses to best suit ratepayers. Further, there is no reason to limit the consideration of benefits to those that were intended. Thus, discernible benefits that directly benefit current ratepayers may be considered on a case-by-case basis. In this case, however, even using the Carriers' interpretation of "useful" as including benefits broadly defined, they fail to satisfy the useful prong, because the they have not demonstrated that SR has benefited ratepayers at all (as discussed below).

1493. The investment must be used and useful to current ratepayers. *Tenn. Gas Pipeline Co.*, 606 F.2d at 1109 ("an item may be included in a rate base only when it is 'used and useful' in providing service. . . . [C]urrent rate payers should bear only legitimate costs of providing service to them. The FPC early adopted the 'used and useful' standard and has not departed from it without careful consideration of the wisdom of requiring current rate payers to bear costs of providing future service."); *Williston Basin*, 48 FERC ¶ 61,137 at 61,538 ("That a utility was not imprudent in making an investment is not necessarily sufficient to warrant the inclusion of that investment in the rate base in the current period, especially where it is not shown that those properties will provide services

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reference to cases on unsuccessful gas supply projects, and in some of these cases, the cost disallowance was based on used and useful. *Id.* at 61,379 n.7.

[742] *Tenn. Gas Pipeline*, 561 F.2d at 957-58.

[743] *Process Gas Consumers Group*, 866 F.2d at 476.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

to ratepayers in the near future."); *El Paso Natural Gas Co.*, 139 FERC ¶ 63,020, at P 125 (2012) ("It is entirely unjust and unreasonable for EPNG to include in its cost of service any expenses associated with the . . . stations [that] clearly will not be used and useful during whatever period the rates established in this proceeding are in effect.").[744] As Staff indicated, the requirement that the investment must be used and useful to current ratepayers is consistent with the Commission's intergenerational equity principle.[745]

1494. In asserting that it is proper to charge existing ratepayers with costs of a project, "the benefits of which all future ratepayers will enjoy,"[746] the Carriers engage in the art of ignoring the text immediately preceding and following the quote. Taken in context, the court stated that "it would be manifestly unfair and improper to saddle current ratepayers with the bill for such research. It is true that RD & D financing is one of those unusual settings in which it is appropriate for FERC to authorize 'the charging to current ratepayers of expenditures incurred by a jurisdictional company' even though the fruits of those expenditures may flow to future ratepayers. In certain circumstances, then, it is proper for FERC to charge existing ratepayers with the costs of a project, the benefits of which *all* future ratepayers will enjoy. It is quite another concept, however, to charge existing ratepayers with a cost that not only brings no benefit to them but, rather, may or will imply future detriment." *Process Gas* thus stands for the opposite proposition than the Carriers assert – that it is uncommon for the Commission to permit recovery in current rates for investments that bring only future benefits.

1495. Carriers' citations to cases where recovery was allowed for investments that were not useful because the benefits were temporary or regulatory policy had changed (Carriers IB 205-06) are unavailing as the benefits for SR were not temporary or intended to be temporary, and there was no change in regulatory policy that rendered SR not useful.[747] The instant case is inapposite to the cases related to RD & D and loans or advances to secure new gas supplies.[748] The booking of additional reserves by the

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[744] *SFPP, L.P.*, 116 FERC ¶ 63,059 at P 26 ("These are speculative *future* events, and therefore establish no present use or usefulness to interstate shippers. . . . Potential—even probable—future cost/rate savings, however, do not satisfy the present use requirement.");

[745] Staff IB 109 (citing *BP Pipelines (Alaska), Inc.*, 125 FERC ¶ 61,215 at n.16 (2008); *Lakehead Pipe Line Co., L.P.*, 65 FERC ¶ 63,021 at 65,132 (1993)).

[746] Carriers IB 206 (citing *Process Gas*, 866 F.2d at 476).

[747] Increased JPO regulatory oversight (Carriers RB 146) does not count as such a policy change. The cases cited are thus distinguishable.

[748] Carriers IB 206 n.111 (citing Order No. 298, FERC Stats. & Regs. ¶ 30,455 at 30,508; *Pub. Util. Comm'n of Colo. v. FERC*, 660 F.2d 821, 828 (D.C. Cir. 1981) (upholding the FERC's approval of rate base inclusion of R&D projects related to

20140227-3052 FERC PDF (Unofficial) 02/27/2014

production affiliate in the instant case, is not comparable to R&D nor analogous to advances or loans. Carriers' citation to *Town of Norwood* for the proposition that recovery is warranted for improvements replacing worn components and improving efficiency to assure that an already used and useful facility could continue to be used and useful (Carriers IB 206-07 citing *Town of Norwood* at 532) neglects the fact that this was a secondary rationale supporting recovery. The court noted that "[t]he primary rationale for allowing Yankee 100% recovery, however, is the language of the Power Contract to which New England Power is a party." The power contracts guaranteed Yankee 100 percent recovery of unamortized investments and operating and maintenance expenses in the event of premature termination. Note that at play in this case also was the fact that retirement of the plant was more cost-effective. *Town of Norwood* at 533. Thus, *Town of Norwood* is inapposite. In the case at bar, the already used and useful legacy facility was 99 percent reliable, and lifecycle replacement of control and communication equipment did not require replacement of the legacy pumps.

Whether the Carriers have shown that SR satisfies the used and useful test by providing discernible, direct benefits to current ratepayers commensurate with costs

1497. On the basis of the precedent discussed above and the fact that no participant disputes that the SR investments at PS 3, 4 and 9 are used, the question now is whether the Carriers have demonstrated that these SR investments provide discernible, direct benefits to current ratepayers commensurate with costs ratepayers bear. As discussed, benefits and costs can be weighed on a broad brush, common sense level, and it is not necessary to take on a detailed accounting project. Thus, the analysis below focuses on whether SR provides an enhanced level of service which would not have accrued to jurisdictional customers absent the project, and which the project was intended by the utility to provide.[749] The costs will be compared to the burdens imposed or benefits drawn by that party.[750] The examination will focus on whether the benefits are commensurate with the level of costs which the Carriers seek to recover through rates. It is noted that the specific facts of this case, where the evidence shows significant affiliate considerations (production affiliate and Carriers), makes this decision more delicate.

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maintaining natural gas supplies); *El Paso Natural Gas Co.*, 22 F.P.C. 260, 269 (1959) (approving recovery for loans related to securing new gas reserves); *Tenn. Gas Pipeline Co.*, 606 F.2d at 1111-16 (approving the FERC's allowance for advance payments aimed at ensuring supplies of natural gas); *id.* at 1099 n.3 (examining the FERC's advance payments recovery policy)).

[749] Staff IB 108.

[750] *Ill. Commerce Comm'n v. FERC*, 576, F3d 470,476 (7th Cir. 2009).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1498. The Carriers contend that the SR project generates net shipper benefits. Carriers IB 203. Although it is the Carriers' burden to establish that the SR project is used and useful, their presentation of the benefits is somewhat scattershot, and they do not break down the costs in a way that associates each alleged benefit with a cost. This limits the level of granularity of the analysis. On the Carriers' account**,** there is no serious dispute that SR benefits shippers and is useful.[751] They categorize their claims largely as lowering costs, enhancing safety**,**[752] replacing allegedly obsolete equipment,[753] mitigating risks,[754] enhancing control**,**[755] improving functionality and operability,[756] reducing emissions, and improving fuel efficiency.[757]

1499. Anadarko and Staff disagree that the Carriers have provided any of these benefits. Staff asserts that because SR has not delivered the economic (or operational) benefits upon which it was premised, it is not used or useful. Staff IB 116.

Costs

1500. Carriers do not separately discuss costs but rather muddle the facts by folding the costs into their claim that the net benefits are not so disparate between the electrification and hybrid options. Carrier IB 232.

1501. According to Anadarko, the Carriers failed to show any net ratepayer benefits. Alternatively, Anadarko asserts that if there are some benefits, the Carriers failed to show that the benefits are commensurate with the massive SR costs.[758] Anadarko's argues that it is illogical to believe that a project that had marginal economic benefit at the initially authorized $220 million would provide any benefit, let alone a commensurate benefit, when the costs are currently $750 million and the project is not finished. Anadarko

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[751] Carriers IB 199-200.

[752] Carriers IB 200 (citing Ex. ATC-954 (Church) at 20; Tr. 8743-44, 8978-79 (Roberts)).

[753] Carriers IB 199-200; Carriers RB 116-17.

[754] Carriers IB 200 (citing Exs. ATC-28 (Baldridge) at 11-13, 26-28; ATC-19 (Howitt) at 23-25, 95-97, 103-06; ATC-917 (Howitt) at 3-4; ATC-32 (Orieux) at 14-19).

[755] Carriers IB 200 (citing Ex. ATC-28 (Baldridge) at 27-28).

[756] Carriers IB 200 (citing Ex. ATC-28 (Baldridge) at 11-12).

[757] Carriers IB 200 (citing Exs. ATC-28 (Baldridge) at 27; ATC-910 (Toof) at 25-25; ATC-914).

[758] Anadarko IB 205 (citing Tr. 234:15-20 (B. Sullivan)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

asserts that for the purpose of used and useful, the costs to be weighed against the benefits are the total costs, including sunk costs. Anadarko IB 206.

1502. Carriers argue that their witness Dr. Toof updated data to reflect amounts actually spent and saved during the project. He took into account evidence that the legacy equipment would have had to be replaced by 2014. Dr. Toof then analyzed the impact of the updated SR costs and updated SR savings and calculated the net present value of SR to shippers at different discount rates. The Carriers maintain that Dr. Toof's analysis showed that the net present value to shippers is positive.

Discussion/Findings

1503. For the used and useful test, comparing electrification and hybrid is not the appropriate baseline. Ignoring their burden to show that SR project costs are used and useful, the Carriers do not come up with a position on costs other than to respond to Anadarko's and State's cost disallowance proposals. Carriers IB 217; RB 131. Thus, the Carriers did not meet their burden to show that SR investments provide benefits to current ratepayers commensurate with costs they bear.

1504. Anadarko is correct that the cost of the SR project is currently in excess of $750 million and the project is not complete. The costs of the project have tripled since the original AFE. The SR project at the initially authorized $220 million was deemed by the Carriers own documents and witnesses to have marginal economic benefit. Ex. SOA-183 at 1; Ex. SOA-259 at 1; Tr. 4949:9-13 (Tudor) (agreeing that even at approval of preliminary engineering the SR Project was considered marginal); Tr. 5044:7-14 (Tudor) ("[T]his was a project that had a lower rate of return than we might typically expect in a project of this magnitude in an established area."); Ex. SOA-259 ("And all this from a project that was practically on life-support when it was approved."); Ex. SOA-256 ("[A]s of Gate 2, [ExxonMobil] management wasn't fully sold that Electrification was the better alternative . . . [and] additional contingency might push us to a different answer (i.e. risk that [ExxonMobil] wouldn't approve the project)!)."

1505. The costs of the project have tripled and there is no evidence in this case showing that the benefits have likewise increased. In this regard, the testimony of B. Sullivan is given significant weight. He testified that "[t]here is no benefits from removing existing turbine legacy equipment and replacing it with the SR equipment. It's a much higher cost without a commensurate benefit to the ratepayer. Tr. 295:9-12.

1506. As Anadarko asserts, the evidence in this case is indisputable that the Carriers have spent $750 million dollars and are not finished on a project which added no new capacity, markets, or independent oil supplies, and was not required by physical obsolescence or any governmental requirement. B. Sullivan's testimony in this regard is given significant weight. He testified that "ratepayers receive the same service today they received prior to the SR project, but at much higher rates." This alone should be dispositive of this issue since under the used and useful test, the Carriers "have to provide

20140227-3052 FERC PDF (Unofficial) 02/27/2014

additional utility to ratepayers." Tr. 337:17-18. TAPS continues to provide oil transportation service from PS 1 to Valdez. This was exactly what was done by the legacy equipment with 99.6 percent reliability.[759]

1507. The replacement of the legacy equipment was not required by regulators or because there were problems with the existing equipment. Pomeroy testified that except for the control systems, SR was not a life-cycle replacement program.[760] Ex. ATC-898 at 12. According to Pomeroy if it had been a life-cycle replacement the first step would have been to evaluate whether the equipment was "fit for purpose." Ex. ATC-898 at 11. He states that it was never assumed that the legacy equipment was not fit for purpose. Ex. ATC-898 at 8. This witness testified that the legacy equipment operated with "very high reliability" and was "well maintained," with "low failure rates, low unplanned shutdowns." Tr. 7980:15-7981:13. B. Sullivan testified that replacing well-functioning equipment in the absence of some regulatory requirement or enhancement to service is unusual. He added that the "legacy gas turbines had significant service value left to provide to ratepayers, and those facilities did not need to be taken out of service because of any government-mandated requirement. They were still fit for service and still- they were robust and reliable. And it's very—it's extremely rare, I don't know of a case where it's ever happened where a pipeline proposed to take out of service well-functioning equipment that still was providing service value. So it was providing service at very low cost for transportation customers." Tr. 252:13-24.

1508. In this case, the inference to be made is that the replacement of well-functioning equipment that is near-fully depreciated with new equipment simply recapitalizes the rate base, thus artificially inflating rates. Thus, there are no benefits to ratepayers since they receive the same transportation service they received before SR, but must now pay for unreliable new equipment (*see* discussion below) when the legacy equipment had decades of remaining service life and would have continued to provide more reliable service than seems possible with the new equipment.

1509. The Carriers relied on point forward economic analysis to justify funding SR at each decision point. Anadarko is correct that this ignores ratepayer benefits since sunk costs are not considered. Dr. Toof testified that "sunk costs are sunk" and "prior expenditures have no place in contemporaneous economic analysis."[761] Dr. Toof's analysis only considers incremental costs or the last increment of costs, thus ratepayer benefits are continually eroded by cost increases. For the used and useful analysis, all

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[759] Tr. 3999:15-4000:16 (always operated at 99-plus reliability and there were a bunch of spare units. Ex. ATC-154 at 31.

[760] Carrier witness J. Ray also testified SR was not a life-cycle replacement. Ex. ATC-18 at 2.

[761] Ex. ATC-36 at 49.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

costs put into rates must be considered in evaluating ratepayer benefits. Anadarko is correct in that when all costs are considered, there are no ratepayer benefits. The economic benefit of SR "was to save $46 million of O&M costs at a capital investment of a couple hundred million dollars. It is clear that after $750 million, . . . that there was no benefit, there were no O&M savings, and there's certainly no benefit when you have to recover that much cost from ratepayers in the form of capital costs . . . it hasn't delivered ratepayer benefits, and the new facilities are not useful in the way that the old facilities were."[762]

1510. Dr. Toof's analysis relies on the faulty assumption that the legacy equipment had to be replaced by 2014. However, this is contrary to the evidence in this case.[763] Moreover, legacy equipment continues to be operated today at PS1 and PS7 (which were restarted to heat oil), which seriously undermines Dr. Toof's assumption. Dr. Toof relied entirely on Alyeska's data without being able to vouch for its quality. Tr. 6041:17-25; 7064:18-21. Dr. Toof repeatedly stated he did not do his own analysis, but relied upon Alyeska's numbers. Tr. 6041:17-25; Tr. 7064:18-21. The Carriers' numbers have been discredited based on the evidence in this proceeding. Dr. Toof further stated that he was not a technical expert and was not able to evaluate the quality of the work or the technical saving issues. Tr. 6041:20-6042:20. Additionally, Toof relied on Alyeska's analysis regarding decreased fuel usage. Tr. 6050:21-6051:2. Dr. Toof admitted that he was unable to comment on the quality of the information that was used. Tr. 6067:16-23. Dr. Toof would not testify as to the accuracy of the underlying engineering analysis. Tr. 7405:16-21. As discussed above, Dr. Toof's testimony is not given any weight.[764]

1511. The Carriers assertion that the legacy equipment would have had to be replaced by 2014 is not credible. As Anadarko points out the legacy equipment continues to operate at PS1,[765] and the Carriers have re-started legacy equipment at PS7 to heat the oil. This demonstrates that the legacy equipment remains capable of providing service. Anadarko

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[762] Tr. 248:7-21.

[763] Carrier witnesses testified the legacy equipment was: well maintained (Tr. 7980:19); very reliable (Tr. 7980:17); had low failure rates (Tr. 7981:2); and low unplanned shutdowns (Tr. 7980:15-7981:3).

[764] Staff is correct that Dr. Toof justifies the benefits of SR solely by reference to future speculative benefits which is contrary to precedent. His alleged benefits have not materialized. Ex. AT-225 at 6.

[765] The Carriers argue that any evidence related to PS1 is irrelevant for deciding whether the SR facilities that are in-service are used and useful. Carriers RB 118. But the state of the legacy equipment at PS1 may be indicative of what the condition of the legacy equipment that was removed at other pump stations at issue would have been had they not been removed.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

also points out that the Carriers' own witnesses testified that the legacy equipment had been "very well maintained," had operated with "very high reliability," "low failure rates," and "low unplanned shutdowns." Tr. 7980:15-7981:3 (Barrett).

1512. B. Sullivan also testified that increased costs due to mismanagement or poor scheduling or poor scoping are not ratepayer benefits.[766] Mismanaged costs of an investment should be disallowed.[767] The evidence described below shows that SR was mismanaged as demonstrated by the increased alarms, poorly implemented UCOS system, the rushed schedule and poor scoping of the project. Again, B. Sullivan testified that the ratepayers do not get any benefits *vis a vis* the costs of for instance, SIPPS. Tr. 250:6-12; Ex. AT-414 at 3. Anadarko is correct that the Carriers have failed to show that any purported benefits of SR or related safety or control system upgrades are not significantly outweighed by the massive SR cost overruns which have been driven by the documented mismanagement of the project.

Benefits

1513. On the Carriers' account, there is no serious dispute that the SR facilities are benefiting shippers, and that the SR costs easily meet the used and useful test.[768] They state that the principal categories of benefits made possible by the SR project are reduced O&M expenses (mostly from reduced staffing) and avoided major maintenance expenses. Carriers IB 220. Carriers contend that SR facilities are currently being used to transport crude oil for the benefit of shippers and that SR lowered O&M costs, improved operability of pumping equipment and control systems, and enhanced pipeline safety by replacing allegedly obsolete equipment.[769] Carriers further offer a somewhat scattershot sequence of alleged benefits that may not be in mutually exclusive categories. They state that replacing the legacy with SR equipment allowed Alyeska to avoid significant major maintenance costs, to significantly reduce personnel and field support costs, as well as to mitigate the reliability, operations and cost risks created by allegedly obsolete control systems and pump station facilities.[770] The Carriers also assert that the new systems

[766] Tr. 250:18-19.

[767] Tr. 250:18-19.

[768] Carriers IB 199-200.

[769] Carriers IB 199-200; Carriers RB 116-17. "Obsolete" means no longer being manufactured, have known operating limitations, and do not have the same capabilities or features of newer units being sold. Further, obsolete equipment can continue to operate for some time and does not need to be immediately replaced. Ex. ATC-28 (Baldridge) at 13.

[770] Carriers IB 200 (citing Exs. ATC-28 (Baldridge) at 11-13, 26-28; ATC-19 (Howitt) at 23-25, 95-97, 103-06; ATC-917 (Howitt) at 3-4; ATC-32 (Orieux) at 14-19).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

enhance the ability to control the pipeline, identify issues and trends early, and perform condition-based maintenance.[771] In addition, the Carriers contend that the "infinitely variable VFDs and smaller pumps greatly improve the functionality and operability of the equipment,"[772] SIPPS and PLCs enhance pipeline safety,[773] and emissions have been reduced and fuel efficiency improved.[774] Carriers also attribute the response to an isolated small oil spill incident as a success of SR.[775]

1514. Carriers also contend that on a strict cost-benefit basis, the evidence demonstrates that shippers will pay lower rates over the life of the SR project than they would have paid if the project had not been undertaken. Carriers RB 117-18; IB 203-04.

1515. Anadarko asserts that the Carriers own figures show that the ratepayers have not benefited from SR. Anadarko's position is that SR provides no benefits to ratepayers beyond what the legacy equipment was already providing at lower cost. Anadarko IB 171, 205.

Discussion/Findings

1516. As determined above, benefits are not limited to intended benefits provided to justify the project, but can include discernible, direct, benefits to current ratepayers considered on a case-by-case basis. In this case, the entire range of alleged benefits put forth by the Carriers may be considered, but only improvements above the baseline may be included (i.e., benefits that were already offered by the legacy system are part of the baseline).

1517. Assuming arguendo that the Carriers achieved their targeted annual $46 million in cost reductions, the cost of service impact of SR was an increase of $104 million in 2010 to get those purported benefits.[776] Tr. 349:10-350:12. B. Sullivan testified that the

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[771] Carriers IB 200 (citing Ex. ATC-28 (Baldridge) at 27-28).

[772] Carriers IB 200 (citing Ex. ATC-28 (Baldridge) at 11-12).

[773] Carriers IB 200 (citing Ex. ATC-954 (Church) at 20; Tr. 8743-44, 8978-79 (Roberts)).

[774] Carriers IB 200 (citing Exs. ATC-28 (Baldridge) at 27; ATC-910 (Toof) at 25-25; ATC-914).

[775] Carriers IB 201.

[776] Tr. 349:10-350:13 (B. Sullivan, citing Ex. ATC-977 and Ex. ATC-978 and explaining that the Carriers' depreciation expense, the return on and of capital, the taxes on the return, the amortization of AFUDC, and the deferred return the total is $189 million. So in just four years, the cost of service has increased by $104 million because

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Carriers' depreciation expense and return components of their cost of service have increased $104 million from 2006 to 2010 and this increase is primarily attributed to the SR project. Tr. 349:10-350:13 and 351:2-5. The Carriers O&M expenses have increased from $357 to $358 (excluding fuel and power costs and ad valorem tax) million during the same period. Tr. 351:6-353:8. B. Sullivan further testified that during the same period fuel and power costs decreased by $15 million, thus the increase in the other elements of O&M, including staff and maintenance costs, is even larger than the overall total numbers reveal. Therefore, B. Sullivan concludes that this figures show not a net benefit but just the opposite, that the rate payer is paying an additional cost. Tr. 349:14-15. This testimony, supported by record evidence is given significant weight.[777] According to B. Sullivan, SR "was really a marginal economic project, a couple million dollars of capital investment. And at $750 million, there is no benefit. It's just a huge rate increase with no benefit to ratepayers, because they get basically the same service they had before." Tr. 234:15-20. Further, Sullivan testified that "from a ratemaking perspective, it violates one of the principle ratemaking aspects, that you do not replace functioning useful equipment and increase rate base and increase cost to ratepayers. Tr. 355:2-6.

1518. Anadarko cites various exhibits to support its arguments that the SR project was undertaken and continued to protect the owners' interests and not ratepayers' interests. These exhibits support Anadarko's contentions. The Scoping White Paper for PS 1 shows that they chose the option to go forward with SR to protect $91 million in sunk costs. The document shows that continuing the SR project at PS1 has negative economics and the "payback period" is "never." Ex. SOA-574 at 26-29. All alternatives to the legacy equipment showed negative economics. *Id.* at 25-29. Anadarko's argument that a project that has no economic benefit and is continued solely to avoid write-offs of millions of dollars does not provide a rate payer benefit, is persuasive. As B. Sullivan testified: "case 1, case 2, case 3, shows that there is a negative net present value and a negative IRR and the project can't possibly have either a net ratepayer benefit." Tr. 369:18-370:3. Evidence shows that BP pushed SR at Supplement 2 to preserve benefits

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of the rate base increase. "So we have a rate base increase in the cost of service, that rate base cost-of-service impact is $104 million from the period 2006 to 2010"). Tr. 351:2-5 (B. Sullivan, explaining that this increase in the Carriers' cost of service is primarily attributable to the SR Project.). Performing the same calculation described by B. Sullivan for the Carriers' 2009 rates (Ex. ATC-16) shows that the rate impact of SR for 2009 is approximately $118 million.

[777] As stated above, the economics of the project were marginal. Tudor explained, that from the beginning, SR has a lower rate of return than Exxon would typically expect of similar projects. Tr. 5044:7-14; 4949:9-13. *See* Exs. SOA-259; SOA-256; SOA-183.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

for its upstream production affiliate (booked reserves).[778] Statements concerning the reserves were made after BP had determined that the SR project was a train wreck. Ex. AT-252. Again, this evidences a disregard for ratepayer benefits.

1519. Contrary to the Carriers assertion the one incident of a cold restart conducted using SR equipment is not sufficient to establish commensurate benefits. As Staff points out this has to be contrasted with the continuous, serious flaws in the operational capacity of TAPS which SR has introduced, for instance, constant alarm flooding in the OCC, *inter alia*. In addition, SR has also made the necessity of cold restarts following leaks and other operational emergencies substantially more likely. Additionally, Anadarko is correct that the recirculation capability the Carriers highlight was not dependent on SR since it was added to the legacy equipment. Tr. 6771:1-25 (Howitt); Tr. 5642:7-16 (Scott). Recirculation is currently being used with the existing legacy equipment on TAPS at PS7. Ex. AT-270; Tr. 5643:9-5644:20 (Scott). The legacy equipment on TAPS is capable of recirculation. There is no hydraulic or mechanical reason TAPS could not operate down to 500,000 bpd with the proper recirculation equipment. (Ex. AT-291 at 514).

1520. Carriers' contention that shippers will pay lower rates over the life of SR is specious. First, there is no evidence of this in this record. Second, even if true, this is an argument for future benefits, as the SR project has not resulted in lower rates to current shippers. And, as discussed above, the precedent does not allow putting these costs in current shippers' rates if they do not benefit.

1521. Additionally, the evidence in this case shows that the 12.9 MW Siemens Cyclone turbine generators installed as part of SR are mis-sized. Alyeska's scoping White Paper for PS1 states that the Siemens TG must operate at 60 percent power to comply with Alyeska's air permit. Ex. SOA-574 at 16.[779] At PS1 this is at a flow rate of 600,000 bpd at flow rates less than 600,000 bpd the TG must be shut down or artificially loaded above the 60 percent threshold to comply with the air quality permit. *Id*. The recommendation is the purchase of three 5MW resistive load banks, with one load bank permanently at PS1, 3 and 4 to "address long-term operability issues by providing an artificial load to keep the Siemens TGs operated at these stations above the low load operational threshold of 60 percent turbine rating." *Id*. at 4. Significant is that this paper characterizes the SR equipment configuration as "providing poor power system flexibility when operating in decreasing throughput conditions." *Id.* at 16. The Carriers' arguments that any evidence

[778] Exs. AT-14 at 3; AT-13; SOA-11 at 17, 22; SOA-386 at 2-3; AT-15 at 3-4. *See also* Ex. SOA-11 at 22.

[779] Johnson testified that for current needs the new Siemens generators have to be operated at roughly 30 percent load but to satisfy air quality permit requirements, these generators must be operated above 60 percent load. Tr. 8483:20-23.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

that PS1 is not part of this proceeding and any evidence related to PS1 is irrelevant for deciding whether the SR facilities are used and useful is disingenuous. First, PS1 is part of the SR project. Second, the evidence of the paper is very relevant to the usefulness of the SR equipment.

1522. As discussed above in the prudence section, this White Paper also considers but rejects the option of maintaining the legacy equipment because it would require writing off $91 million in SR investment. Ex. SOA-574 at 5, 12. Similarly, the same document evaluated two options for generators, with the option specified for SR calling for more power than the other. The document determined that the less powerful configuration would be "the preferred technical option based on currently available information and long-term operational stability" but rejected it because of "the near term $11 MM write-off expense associated with not completing the 12.9 MW TG installation." Ex. SOA-574 at 6.

1523. In addition, the White Paper suggests that if installed, the Siemens Cyclone may not be used if throughput falls below 600,000 bpd.[780] At throughput below 600,000 bpd, the Power Load Strategy for PS1, would not place any load on the Siemens Cyclone. At this throughput (below 600,000 bpd), the 7 MW power requirement would be met with the Taurus generator plus the 3MW substation being installed as part of SR. Since TAPS throughput is currently between 550,000 and 600,000 bpd,[781] it appears that the new 12.9 MW Siemens Cyclone will likely not be used. Johnson confirmed for current needs, the new Siemens generators need to be operated at roughly 30 percent load. However, to satisfy the air quality permit requirements, the Siemens generators must be operated above 60 percent load. Tr. 8483:20-23 (Johnson). *See* Ex. SOA-574 at 4, 16. Anadarko is correct that installing a 12.9 MW Siemens Cyclone Turbine simply to avoid write-offs, when the power needs can be more appropriately met by other options, is not used and useful to ratepayers.

1524. Anadarko points out that PS1 facilities may never be used. This would have to be determined in the future. Anadarko is correct that utilities cannot be encouraged to build facilities which will not be used. Under the Carrier's proposed test, the facility will not be used therefore, it will never be useful. Installing a more powerful turbine that is not used in order to avoid write-offs fails the first part of the used and useful test, as the turbine is not used. And if it is used, but a less powerful turbine would have been completely adequate, then the more powerful turbine is not useful.

O&M and major maintenance expenses have not decreased

[780] Ex. SOA-574 at 19 (Table 1 – Power Load Strategy at PS01, showing at throughputs less than 600,000 bpd, PS 1 requires 7 MW or less of power, and the Siemens Cyclone handles 0% of the load).

[781] Tr. 7011:8-11 (Howitt).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1525. Anadarko asserts the primary goal of the SR project was O&M cost reduction and that these reductions were to be based on savings from reduced staffing and lower major maintenance costs. Anadarko IB 176. Anadarko reiterates that the pipeline was running reliably and that the sole driver for the SR Project was cost savings. Anadarko IB 194-95. Anadarko counters the Carriers arguments on maintenance and personnel by stating that staffing has not significantly decreased,[782] but has been regionalized[783] and/or replaced with contractors. Further, AT asserts that some of the staffing reductions should not be attributed to SR.

1526. Staff asserts that SR "has not produced a scintilla of benefit" to independent shippers, and thus the Carriers have not shown SR to be used and useful. Staff IB 110.

1527. Carriers assert that Anadarko underestimates the total level of SR's O&M savings by improperly using Alyeska's 2004 LRP instead of the 2002 LRP. Carriers contend the SR project improved TAPS by replacing obsolete systems and equipment, and that the legacy equipment would have had to be replaced by 2014, even if SR had not proceeded,[784] and that they did not foresee this in 2002-03.[785] The Carriers base this on the claim that the legacy equipment "continued to deteriorate" and "the implications of low flow on the suitability of the legacy equipment," and that Alyeska "reasonably believed" that finding replacement parts for the legacy equipment would be difficult and costly.[786]

1528. Carriers also contend that Anadarko's analyses "essentially ignore the extent to which operating costs would have increased at a much faster rate without SR,"[787] and that Carrier witnesses detail the specific costs that were reduced or avoided in this period as a result of SR. Carriers IB 204-05.

Findings/Discussion

1529. As discussed above, the major maintenance savings projections were flawed and personnel reductions have not materialized. Ex. SOA-718. Reduced staff has been replaced with third party vendors. Tr. 6831:7-14. Maintenance staff and rovers remain at

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[782] Anadarko IB 68-72, 176-79; Anadarko RB 97.

[783] Anadarko IB 177 (citing Tr. 6852:1-6853:20, 6870:12-22 (Howitt)).

[784] Carriers IB 203 (citing Ex. ATC-384 at 8-9); *see also* Exs. ATC-18 (Ray) at 48-50; ATC-19 (Howitt) at 104-106; ATC-28 (Baldridge) at 12-13.

[785] Carriers IB 203.

[786] Carriers IB 203-04.

[787] Carriers IB 204.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

PS 4 and use all of the facilities. Tr. 6849:5-24; 6858:18-21. Technicians are still working at PS9. Tr. 6852:18-23.

1530. As Anadarko points out, from the evidence in this case, it is not clear whether any staffing reductions can be attributed to SR. Carrier witnesses Howitt and Johnson admitted that a program started in 2002, Strategic Realignment, reduced Alyeska headcount by 300 (150 Alyeska employees and 150 contractors). Tr. 7097:6-23; *see* Tr. 8300:1-9. Howitt testified that 263 further reductions are attributable to SR.[788] However, this includes job reductions that occurred before SR became operational (February 2007). Tr. 7098:17-7100:8 (Howitt). As a matter of fact, "every time an employee departed Alyeska since AFE S020 was submitted (and not yet approved) was attributed by Howitt to SR." Tr. 7099:19-7100:4 (Howitt). Moreover, Alyeska personnel who took lucrative severance packages were contracted back by Alyeska. These employees are known as retreads."[789] Further, many staffers have had their title changed from employee to contract employee.

1531. Evidence in this case also shows that Alyeska personnel have questioned whether indeed there were staff reductions as a result of SR. For instance in 2006, Lang questioned the proposal to have two field engineers stationed at PS1 after SR and characterizes this staffing as "grossly inadequate" asserting that engineering issues will not disappear after SR. Ex. AT-530 at 8. Lang also stated that SR estimates had been wrong. *Id*. at 9. As far as why the staffing choices had been made (2 field engineers) Lang stated:

> what appears to me is that when the proposal for S/R was made to the owners, the S/R team painted the cost, schedule, and return on investment as positive as they had to in order to get the owners to "Bite" on the project, regardless of truth and fact. Now that implementation is moving ahead, the reality of cost and scheduling is charging through the S/R team like a bull in a china store, and everyone is trying to run from it. The same is true with the proposed staffing after S/R. The plan proposed was unrealistically optimistic in order for the project as a whole to look more attractive to the owners. But sooner or later there will be a reality check on this staffing plan. I am making efforts to have that reality check take place sooner rather than later.

Id. at 9-10.

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[788] Ex. ATC-917 at 15:8.

[789] Ex. AT-452 at 7 (explaining that there are retreads at PS3 and 4). Howitt testified severance packages received by former Alyeska employees was 65 weeks of base pay. Tr. 7105:17-21. Following. Howitt's severance package calculation, the package received by Howitt was approximately $300,000. Tr. 7116:13-15.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1532. Carrier witness Johnson testified that Pomeroy and Howitt were "pushing the envelope in terms of their staffing analysis of SR. Tr. 8271:24-8272:3. Additionally, Howitt at the hearing upon looking at a Pipeline Organization Chart for PS 1 noted that the chart showed more people at the pump in the future than there are currently. Tr. 7141:13-17.[790]

1533. Additionally, B. Sullivan explained that TAPS O&M expense post-SR (in 2010) is actually *higher* than pre-SR (in 2006, prior to the 2007 startup of SR facilities), even after controlling for changes in ad valorem taxes and fuel and power costs." Tr. 351:6-353:8 (B. Sullivan) (Discussing testimony of G. Grasso, AT-435 at 9, and comparing to Ex. ATC-977).

1534. Pump stations have not been completely demanned as planned: "all pump stations where SR has been performed, Pump Station 3, Pump Station 4, and Pump Station 9, continue to be manned and any reduction in staffing attributable to SR is marginal if it exists at all," and "the dream of completely un-manned pump stations has not been achieved" Ex. SOA-720; Tr. 7273:11-7274:14 (Howitt); SOA-721 at 4; Tr. 7276:5-15 (Howitt)) (showing that pump stations have not been completely demanned). And personnel changes, accounting for Alyeska redesignating and moving personnel, have not been significant: "current headcount at Alyeska has fluctuated from 818 in 2005, prior to the 2007 startup of SR equipment on TAPS, to a low of 763 in 2010, and back up to [a planned] 813 in 2012." Ex. AT-492 at 1-2.

1535. Staff is correct that the Carriers' projected cost savings from major maintenance, O&M, and personnel reduction were not realized on the TAPS System as a result of SR. Moreover, record evidence shows that some costs will increase as a result of correcting deficiencies in the SR design not addressed by the project. Staff correctly points out that in sanctioning the SR Project in AFE S020, the TAPS Carriers projected $384 million in avoided major maintenance as a benefit of the SR Project (setting aside the fact that the estimate was critically flawed), but that not a single dollar of this in savings was realized. In fact the projection is that maintenance expenses will increase going forward.[791] Additionally, as Staff points out, from 2003-2009, Alyeska's major maintenance expenses have been relatively constant. This is explained by an Alyeska engineer circa 2005, "[m]ost of the engineering work at the [pump] stations will not even be impacted by anything S/R does, so the workloads after S/R will be no less than now." Ex. SOA-167 at 2. The same engineer predicted that these costs "likely will dramatically increase as a result of correcting numerous deficiencies in the S/R design that was not addressed

[790] *See* Ex. AT-453 at 1.

[791] Staff IB 111-112 (citing Ex. SOA-60 at 9).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

by the project." *Id*. This assessment was confirmed by other Alyeska engineering personnel as "accurate if not understated."[792] *Id.* at 1.

1536. O&M the other anticipated benefit of SR has not decreased. This was to be realized through reduced staffing and reduced annual maintenance expense based on regionalization. Ex. SOA-60 at 14. As Staff correctly points out, these expenses are projected to increase on a going forward basis. The SR projection was that O&M would be reduced by $899 million over the 20-year planning horizon for SR. *Id*. at 9. O&M expenses from 2003-2010 have remained relatively constant. Ex. AT-248. However, deeper examination shows that personnel and annual (non-major) maintenance have steadily increased. *See* Ex. AT-437; AT-442 (personnel expense); AT-440 (maintenance expense). The projection of future O&M expense shows these costs continuing to rise throughout the period in which the original projection claimed would be lower. *Id.* (showing continued increase in yearly O&M expense through 2015 in the 2011 LRP); Ex. AT-435 at 13-14 (Grasso showing projected increases in O&M expenses through 2022 in Alyeska's 2013 LRP).

1537. Staff is correct that the Carriers argument that the 2002 instead of the 2004 LRP should be used to compare O&M is flawed in a number of respects. First, while the 2002 LRP does indeed project costs under the inertia scenario, it fails to capture non-SR cost savings initiatives which occurred in subsequent years and were captured in the 2004 LRP. Ganz admitted that the 2004 LRP had electrification as the base case assumption. Tr. 7822:9-20; Ex. S-24 at 3. Further, the 2004 LRP calculation of the actual O&M expenses in 2004 (prior to SR) had dropped substantially (by $80-$100 million overall) relative to the 2002 LRP projection for 2004. Tr. 7824:13-18. As a result, Staff points out that O&M expenses had dropped substantially between 2002 and 2004, and that decrease was in no way attributable to the SR Project." This was the result of non-SR initiatives such as "strategic realignment"[793] and "system renewal"[794] which resulted in substantial reductions in Alyeska headcount and related labor costs. Staff is correct that these savings should not be counted as SR project benefits and Ganz' protestations to the contrary are disingenuous. As Staff correctly points out, the proper baseline for measuring the benefits of SR is the 2004 LRP. Ganz own testimony shows that the projected O&M costs after 2005 under SR (blue line) were supposed to drop significantly. However, the actual O&M costs after that time (red line) actually

[792] As Staff points out, many buildings which originally were projected to be taken out of service were retained, and had to be fitted with fire and gas system upgrades, further increasing major maintenance expense on the system. Ex. SOA-150 at 11.

[793] Tr. 8499:14-22 (a reduction in force in 2002); 7097-98:12-5 (realignment started in 2002, reduced workforce by 300 people).

[794] Tr. 7804:11-23(management activities such as information system renewal to reduce costs).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

increased. Ex. ATC-960 at 6. Therefore, Staff is correct that independent shippers have not received any benefit from the SR project in the O&M category.

1538. Anadarko correctly points out that Ganz did not successfully contradict the testimony of Anadarko's witnesses Hisey and Grasso concerning the lack of SR benefits. First, Ganz was unable to defend his testimony on cross examination. Second, his use of the 2002 LRP as a baseline for measuring benefits, as stated above, has been rejected. Ganz did not investigate or confirm any of the numbers used in the draft 2002 LRP he used. Tr. 7794:6-21. He also did not investigate whether the 2002 LRP savings were ever realized. Tr. 7803:13-17; 7804:2-6. Ganz was unsure if the numbers he used included staff reductions resulting from strategic realignment. Tr. 7818:2-11.

1539. As discussed above in the prudence section, the Carriers major maintenance savings were found unreasonable and not given any weight. It was based in large part on "what you don't know instead of what you do know" or a 10 year projection doubled.[795] Tr. 4455:3-4456:19; 6977:22-6978:5. Further, Hisey testified that the mainline units were never the major drivers of major maintenance expenditures. He stated that right of way repairs and other pipeline maintenance were the significant drivers of major maintenance costs. Tr. 3956:10-18.

1540. B. Sullivan explained that the Carriers' own figures show that the ratepayers have not benefited from SR. He explained that the Carriers' depreciation expense and return components of their cost of service have increased $104 million from 2006 to 2010, primarily attributable to the SR project. Tr. 349:10-350:13 (B. Sullivan, citing Ex. ATC-977 and Ex. ATC-978). Tr. 351:2-5 (B. Sullivan). During the same period, the Carriers' O&M expenses actually *increased*, from approximately $357 million to $358 million, with fuel and power costs and ad valorem tax factored out (fuel and power costs decreased by $15 million during that period) Tr. 351:6-353:8 (B. Sullivan, citing Ex. AT-435 at 9 and Ex. ATC-977).

1541. As discussed above, the evidence in this case conclusively demonstrates that SR was largely a capital project designed to lower operating costs. Tr. 4604:8-13 (Howitt). *See, e.g.,* Tr. 4779:16-17 (Yaege) ("first and foremost, this project was driven by a desire to reduce costs."); Tr. 4604:8-12 (Howitt agreeing with Commissioner Wilson that "the sole driver . . . for the SR project was cost savings."); Ex. ATC-18 at 12 (Ray, stating that SR "was a strategic project undertaken to change fundamentally the cost structure of TAPS and better position TAPS for future cost-effective operations as throughput continued to decline."); Ex. ATC-20 at 23 (Rabinow stating that the goal of SR was "to provide another 30 years of efficient and economical service. Long-term and short-term economics were both critical to our evaluation of alternatives and to the Strategic Planning Team's charter."). Tr. 4604:8-13. The O&M savings would be the result of savings from reduced staffing and lower major maintenance costs. Ex. ATC-24 at 23.

[795] *See* Ex. SOA-718 ($1 becomes $28.80 over a 20 year period).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

However, as found above, the Carriers have not demonstrated any such savings from SR. Tr. 351:6-353:8. Further, as Staff points out, personnel reduction, reduced major maintenance, and associated cost reductions were equally achievable under the far-simpler and cost-effective brownfield hybrid option.

1542. As discussed above, the SR pump stations continue to be manned and any staff reductions attributable to SR are negligible. The dream of completely un-manned pump stations has not been achieved. Ex. SOA-720. Although maintenance personnel have been regionalized this has not resulted in reduced overall staff numbers in any meaningful way. *See* SOA-90. Headcount at Alyeska for the pertinent years was: 818 in 2005 (prior to the 2007 startup of SR); 763 in 2010 and back up to 813 in 2012. Ex. AT-492 at 1-2.

1543. Anadarko contests the Carriers claim that Alyeska "reasonably believed" that finding replacement parts for the legacy equipment would be difficult and costly. Anadarko is correct that the Carriers beliefs do not amount to proof that installation of SR was required by spare part problems. Anadarko is also correct that the evidence in this case shows that spare parts and support for the legacy equipment was available. Rolls-Royce, The Wood Group, and Trans Canada Turbines continue to support the Avon and Rolls-Royce continues to manufacture parts. Ex. SOA-543 at 14-15. DeHaas stated "[t]here is no immediate problem in regard to obsolescence issues, on the Avon. It will continue to be serviceable for many years into the future." Ex. SOA-24 at 1; Ex. SOA-19 at 2; Tr. 1020:4-22 (Sanders); Ex, SOA-542 at 35. State's witness Sanders stated Alyeska did not adequately consider decommissioned equipment as a source of spare parts. Ex. SOA-425 at 29; *see* Tr. 1022:13-20 (Sanders).

1544. The Carriers claim that net of *ad valorem* taxes, the increase in the Carriers' costs from 2006 through 2010 was only about one percent per year, but the average annual cost increase for the oil pipeline industry over essentially the same period was more than 5 percent *per year*. Carriers IB 205 (citing Phase II Tr. 314 and *Five-Year Review of Oil Pricing Index*, 133 FERC ¶ 61,228 at P 14 (2010). But this analysis does not compare the cost increases between the legacy and SR equipment, which as the Carriers state (Carriers IB 204) is the relevant comparison. Anadarko is correct that this argument is specious. The increase in ad valorem taxes is irrelevant to determine the impact of SR.

1545. B. Sullivan testified that using the Carriers' own numbers, from 2006 to 2010, when *ad valorem* taxes and fuel and power costs (which decreased by about $15 million) are removed, the Carriers' O&M expenses *increased*, from approximately $357 million to $358 million. Tr. 351:6-353:8 (B. Sullivan, citing Ex. AT-435 at 9 and Ex. ATC-977). Since fuel and power costs decreased during the period, this means that the increase in the other elements of O&M, including staff and maintenance costs, is larger than the overall total numbers. B. Sullivan concludes that this does not show a net benefit, "they represent just the opposite, that the ratepayer is paying an additional cost." Tr. 349:14-15. In reference to the O&M cost increases B. Sullivan testified, "the O&M has continued to go up, and you spent $750 million to continue to have an increase in O&M

20140227-3052 FERC PDF (Unofficial) 02/27/2014

costs. I mean, the simple fact is that there is no net benefit because you spent so much money to try to cut O&M cost that there is no net benefit to ratepayers." Tr. 314:14-19.

Reliability

1546. Carriers claim that TAPS system reliability post-SR has remained above 99 percent, and there have been no deferred barrels attributable to SR commissioning, startup or equipment operation. Carriers RB 155.

1547. Anadarko argues that the legacy equipment was highly reliable and that SR did not increase reliability and may have reduced it making it less beneficial to ratepayers. Anadarko RB 97-98; Anadarko RB 101. Anadarko counters that the Carriers have deceptively changed their definition of reliability to system reliability to meet their target. Anadarko IB 203; RB 103.

Findings/Discussion

1548. Anadarko is correct that a key indicator of reduced reliability is the number of times the pipeline is shut down (unscheduled). This had been the standard for decades prior to the failure of the SR MLUs to achieve that standard. Prior to SR TAPS had few shut downs. Evidence in this case shows that the TAPS legacy equipment was considered highly reliable. From July 28, 1977, through December 31, 2000, the pipeline operated for over 204,000 hours and was shut down for 852 hours total, which is a reliability rate of 99.6 percent. Ex. AT-165 at 4. *See* Tr. 7980:17-7981:3 (Pomeroy) (explaining that with legacy equipment, TAPS reliability was "very high" based on "reliability and low failure rates, low unplanned shutdowns."); Ex. ATC-154 at 31 ("The major mechanical equipment is operating extremely well. Reliability is high and unplanned shutdowns are rare.").

1549. The period prior to SR, TAPS was extremely reliable with few shutdowns. From 1998 – April 2007, annual shutdown totals on TAPS ranged from 5 to 18. Ex. AT-500. Since the start of SR in 2007, the number of times TAPS has shut down has markedly increased. In 2011 there were 41 shutdowns,[796] which more than doubles the 18 shutdowns experienced in 1999, which was the highest yearly total in the previous nine and a half years. It is noted that the target level of shutdowns for 2011 was 32. From January – July 2012, there were 26 shutdowns with an annual target of 28. Ex. AT-499. So at a minimum it can be seen that post SR the target has significantly increased (64% from the peak of 18 in 1999).

1550. Anadarko posits that the way reliability is measured can mask the reliability problems caused by SR. Reliability for the Right of Way Renewal was measured by evaluating the shutdown time vs. the time TAPS was operating. However, the Carriers

[796] Ex. AT-499 at 3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

have changed the definition of reliability to "system" reliability which considers the "system" reliable so long as the PS1 tanks are accepting oil even if every SR MLUs is broken down. Tr. 6772:16-6774:17. They have changed the focus and standard of reliability from positive forward flow to looking at deferred barrels. Carriers define reliability in terms of deferred barrels, meaning that if TAPS is 99.6% reliable, then only 0.4% of barrels offered for shipment were not shipped. Anadarko IB 203 (citing Tr. 6773:11-20 (Howitt)). With this definition, given the amount of excess capacity currently available, the entire pipeline could shut down and no barrels would be deferred until the tankage at PS1 became full. Tr. 6773:21-6774:17 (Howitt).[797]

1551. Pre-SR, when TAPS operated at much higher volumes, the legacy equipment was in service moving oil 99.6 percent of the time. Now, due to the Carriers redefining reliability to system reliability, Anadarko claims, with excess capacity, much of the equipment could be out of service and the Carriers can still claim high reliability. According to Anadarko, the reliability percentages reported by the Carriers do not indicate that the SR project is providing a benefit to ratepayers. Under their new standard, TAPS can achieve 100 percent reliability even when the system is unable to achieve positive forward flows because of tank storage at PS1. As long as producers are not given prorated barrels within any given month, TAPS' reliability standards have been met. Anadarko cites to one email in support of the contention that the Carriers have changed the metric for reliability to meet their target. Ex. AT-498 at 1. The Carriers changed the definition of reliability to "system" reliability which considers the "system" reliable so long as the PS 1 tanks are accepting oil. Tr. 6772:16-6774:17 (Howitt). Tr. 7991:21-7992:3 (Pomeroy). Concerns about the metric have been expressed. "My fear is1) that we are slowly diluting the meaning of this metric in order to meet a company target and 2) by weeding out the events that do not meet the criteria of a 2124 form, we loose [sic] the opportunity to correct a possible defect that could worsen over time." Ex. AT-498 at 1. Anadarko is correct that this new metric does not indicate any ratepayer benefits and instead masks reliability problems created by SR.

1552. Additionally, Anadarko is correct that another indicator of reduced reliability is the drastic increase in the number of alarms produced by the SR equipment. For instance, at PS 9, prior to SR, there would be approximately 2000 alarms in one 24 hour period. After SR was activated, it increased to 120,000 alarms. Ex. AT-405 at 36; AT-433 at 16. As Anadarko points out, the increase in alarms, including alarm "floods" are significant because operators cannot effectively evaluate and resolve alarms at the rate that the SR equipment generates them. Carrier witness Church agreed with the Alarm Management Handbook, which states: "[h]igher numbers represent thresholds above

[797] Pomeroy testified that he was "unaware of any limitations" on the amount of additional tankage that could be installed at PS1 to enhance system reliability." Tr. 799:9-13. He also confirmed that at reduced throughput, "you do end up with additional capacity that you can use to make up reliability." Tr. 7991:21-7992:3.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

which proper alarm response becomes less likely, alarms are likely to be missed, and operational performance is potentially affected. Tr. 7518:19-7519:1; Ex. AT-461 at 10. The Handbook also points out that "[a]larm rates above approximately 300 alarms per day place the operator in the unenviable position of being forced to ignore many alarms – the quantity simply overwhelms their ability to analyze each one. Ex. AT-461 at 17; Tr. 7522:5-14.

1553. In response to the Carriers arguments about the lack of spare parts for the legacy equipment, Anadarko points out that Alyeska did not determine what spare parts it had. Anadarko RB 102. State's witness Sanders stated, Alyeska did not adequately consider decommissioned equipment as a source of spare parts. Ex. SOA-425 at 29; *see* Tr. 1022:13-20 (Sanders). Additionally, Anadarko is correct that the evidence shows that spare parts and support for the legacy equipment was available. Rolls-Royce, The Wood Group, and Trans Canada Turbines continue to support the Avon and Rolls-Royce continues to manufacture parts." Ex. SOA-543 at 14-15. Further, the evidence in this record clearly indicates that there were no obsolescence issues with the legacy pumps. DeHaas stated "[t]here is no immediate problem in regard to obsolescence issues, on the Avon. It will continue to be serviceable for many years into the future." Ex. SOA-24 at 1; Ex. SOA-19 at 2; Tr. 1020:4-22 (Sanders); Ex, SOA-542 at 35."

Mismanaged implementation of SCADA

1554. Anadarko states that an increase in the number of alarms increases problems and risks with safety, environmental, reliability, maintainability, and operability[798] because the OCC controllers cannot respond to all of the alarms and will have to ignore more of them.[799] Anadarko also contends that the Safety Integrity Pressure Protection System (SIPPS), a reactive safety system installed as part of SR which is supposed to act as a fail-safe to avoid overpressure on the pipeline, does not provide any benefit because its implementation was mismanaged and reliability questionable. SIPPS was designed with little input from the relevant Alyeska personnel, and in April 2010, SIPPS experienced a failure which resulted in the shutdown of TAPS. Anadarko IB 204-05[800]

1555. Staff does not contest the prudence of those upgrades at the time they were originally sanctioned, since the evidence adduced at the September 2012 hearing clearly demonstrates that the SCADA system has not only failed to deliver its intended benefits,

[798] Anadarko IB 184.

[799] Anadarko IB 181 (citing Tr. 7518:19-7519:1 (Church); Ex. AT-461 at 10; Ex. AT-461 at 17; Tr. 7522:5-14 (Church); Ex. AT-532 at 2; Ex. AT-476 at 1; Ex. AT-475 at 1).

[800] Citing Tr. 7663:5-13 (Church); Ex. AT-408 at 1; *see* Tr. 8715:8-11 (Roberts); Ex. AT-473 at 2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

but has actually made the TAPS system significantly less reliable than it was before. As such, the TAPS Carriers have failed to prove that the SCADA system is used and useful to TAPS ratepayers, and it should therefore be excluded from rate base. Staff IB 144-45. Staff argues that flawed implementation of SCADA upgrades has resulted in a control and alarm system which is drastically less safe and reliable than that which came before, and provides no benefit to the TAPS shippers. Staff IB 116. It has led to constant alarm flooding in the Operations Control Center in excess of Alyeska's own goals, rendering TAPS system controllers significantly less able to respond to emergency events on the system. Staff IB 116. Thus, the $8.4 million SCADA system upgrade should be *excluded* from the Carriers' rate base because the Carriers have "failed to prove that the SCADA system is used and useful to TAPS ratepayers." Staff IB 115-16, 144-45. Staff supports Grasso's disallowance proposal[801] of removing the capital additions attributable solely to Electrification from the total Additions to Property in Service for the rate years at issue in this proceeding under the use and useful standard including the SCADA costs.

1556. Carriers counter that Staff's and Anadarko's positions ignore Alyeska's conclusion in September 2002 – which no participant disputes – that replacement of the SCADA system was required "to maintain Pipeline Operational Integrity" and because "[t]he cost of maintaining the existing SCADA system with its current functionality is expected to become prohibitive as the hardware vendor discontinues system support in the next two to three years."[802] Carriers claim that excluding SCADA upgrades on the basis of the alarms is not justified. They mention that reliability remained above 99 percent and there have been no deferred barrels attributable to SR commissioning, startup or equipment operation.[803] Carriers claim witnesses in this proceeding who have direct responsibility for the control of TAPS operations testified that the new control system, including the SCADA upgrades, have greatly *enhanced* the safety and control of TAPS operations.[804] In fact, the Carriers state that the pipeline can operate safely without the alarms.[805]

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[801] Ex. AT-225 at 4-5; Tr. 4297:13-20.

[802] Carriers RB 154,155 (cting Ex. ATC-152 at 1-2 (AFE F370 requesting $8.4M to replace SCADA)). Cited material is actually at ATC-152 at 6.

[803] Citing Ex. ATC-917 (Howitt) at 28. But the reliability metric was changed to make high reliability more easily achievable post SR and thus meaningless.

[804] Carriers RB 155 (citing Tr. 8977-81 (Roberts stating that "I'm not aware that they've ever shut down the pipeline because they felt overwhelmed by too many alarms." And in reference to a question on control "I think we have greatly enhanced.")). Ex. ATC-954 at 20 (Church stating "Although SR has resulted in a substantial increase in the number of alarms, it has not affected the pipeline's ability to be operated safely and reliably. Although OCC controllers play an important role in ensuring the safety of the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Findings/Discussion

1557. The number of alarms after SR is documented in the PlantState Suite reports (PSS). Ex. AT-481. "PSS" documents the increase in alarms. For September 2007, the report states that TAPS had a daily average of 1,078.77 alarms, far higher than the goal of 150 alarms. Hourly average was 44.95 (the goal was 5), and 30.23 percent of the time was spent in alarm floods. Ex. AT-481 at 3. In July 2007, the PSS report showed a daily average of 2,506.90 alarms (the goal was 150), with an hourly average of 104.45 (the goal was 5). Ex. AT-483 at 2.

1558. The evidence in this case establishes that OCC must monitor about three and a half times more alarms than before,[806] and in 2007 those alarms were going off about a thousand to two and a half thousand times a day. Ex. AT-481 at 3; AT-483 at 2. The preponderance of the evidence supports Anadarko's and Staff's positions that the current SCADA system is incomplete, suboptimal, and producing an excessive number of alarms.

1559. For Alyeska, CS-360 established the standards for alarms. Until July 2012, the long-term targets for alarms were as follows: alarm rate (5 per hour and 150 per day), no disabled alarms, and no chattering alarms. For the week of July 29, 2012, through August 5, 2012, there were 18,000 total instances of alarms of which 6,884 were chattering alarms and 2,243 unique alarms. For that same week, the system weekly time in alarm was 19.76 hours. Ex. AT-466 at 66 (Table 9). Ex. AT-480 at 128, 130, 132.

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pipeline and pump station equipment, SR also includes engineered, automated systems to protect the integrity of the pipeline and pump station equipment. These automated systems operate independently of the SR alarm system.").

[805] Carriers RB 104 n.133: Church, Alyeska OCC Manager, testified, alarms are but one small part of the much broader set of tools that controllers use to operate TAPS safely. Tr. 7540-41, 7553-54 (Church). In fact, TAPS could be safely operated *without* alarms if necessary. Tr. 7677, 7741, 7753 (Church); *see also* Ex. AT-433 (Hiebert Deposition) at 27 (Tr. 116) ("[Y]ou could also run a pipeline without an alarm system, and only run it with SCADA and run it safely, because you have your operational awareness of your field equipment."). Ms. Hiebert stated emphatically that she did not believe the safety or integrity of TAPS operations had been compromised by the new alarm system. Ex. AT-433 (Hiebert Deposition) at 27 (Tr. 114) ("I did not feel that we had hampered the safety and integrity of the pipeline, because the safety system would still shut down if there was equipment malfunctions.").

[806] Ex. AT-532 at 2; Carrier witness Roberts stated the estimated alarm points being 35,000 for SR was a pretty close estimation. Tr. 8820:22-8821:6 (Roberts).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

These averages far exceeded the goals, Church testified[807] that Alyeska removed all of the alarm management goals from Alyeska's Alarm System Standard. The SCADA system has not met Alyeska's prior standards for alarms. As concluded above, the inference is that the metrics were removed because they could not be achieved.

1560. Carriers claim that witnesses testified that the new control system, including the SCADA upgrades, have greatly *enhanced* the safety and control of TAPS operations. However, these witnesses did not contradict the testimony concerning the safety issues created by the increased number of alarms preventing safe operations of TAPS and this testimony is contradicted by significant evidence in this record. Therefore, it is found that the testimony is not credible.

1561. After SR went online the HMI Work Group reported (Progress Report dated March 31, 2007): "[i]n any case, [it] remains that this alarm system is not fit for its intended purpose and [will place] the OCC and the entire TAPS system at a higher level of risk." Ex. AT-414 at 3. The report continued: "if not corrected now, the level of risk will continue to increase with every additional S/R facility alarm stream brought on line." *Id.* The report states that before SR there were approximately 9, 200 alarms and after full implementation of SR, the OCC will be responsible for 35,000 alarms."[808] *Id.*

1562. OCC Controllers report that the number of alarms has affected them. Eldridge (an Alyeska OCC supervisor) stated that "we received more alarms than is humanly possible to respond to in that time frame." Ex. AT-476. Eldridge stated "[a]s far as I can determine, there is yet to be a document that establishes the HMI Standards for the OCC and subsequently, the entire UCOS SCADA System. The delay has already been voiced as a significant risk in one of the projects." Ex. AT-406 at 2. Another employee, Glenny reported that it is not possible to respond to over 1300 alarms in 10 minutes. "In fact, during another upset at PS04, PS09 coincidently shut down but the controller was wading through so many alarms from PS04 that losing PS09 went unnoticed until another controller came over to assist." Ex. AT-475. A 2007 risk assessment stated: "[p]resently, the rest of the organization is in a state of denial and not prepared to deal with this reality. It is clear to all OCC personnel that it is here now. A solution is needed now, before the remaining 20,000 alarm Tsunami comes ashore with addition of the remaining Pump

[807] In July 2012, the long-term targets were removed. Tr. 7638:9-13 (Church). Alyeska removed all of the goals from their control system guidelines in order to make them "audit friendly." Tr. 7564:5-24 (Church).

[808] A 2007 email states that the "problems with the alarm management scheme are so broad and far reaching that there is no possible quick fix. The process is fatally flawed at its foundation and all of the subsequent structural decisions are flawed as a result. Ex. AT-515 at 1.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Stations." Ex. AT-516 at 4. Carrier witness Church confirmed that these reports were not "cherry-pick[ed]" to find the worst reports. Tr. 7708:17-21.

1563. OCC Controllers see the alarms and have to understand them and identify the source of the problem. Anadarko points out that this is difficult since the alarms have not been properly tagged. Uncontroverted evidence in this case shows that in November 2005, Alyeska did not have a "[c]ompany tagging philosophy that defines the ownership and differences of the two equipment lists." Ex. AT-505 at 2. A few months before PS 9 was to go online, in October 2006, there were "approximately 200 'critical' equipment items that needed to be added to the Passport system for PS09 startup" and "approximately 2,400 non-critical equipment items for PS09 that" would "be incorporated into the Passport system after startup." Ex. At-504. Anadarko is correct that the OCC controllers were forced into a position where they were unable to safely and reliably manage the pipeline because the necessary preparations did not occur.

1564. Further, evidence in this case shows that the implemented control system has become more difficult to manage and control. The new control system UCOS has added complexity and made the jobs of pipeline operators more difficult. For PS 9, the number of screens for the SCADA system increased from 6 prior to SR to 280 with SR.[809] Ex. AT-408 at 1. V. Hiebert stated: "We are at our wits end trying to decipher the SR control software to find some common threads of logic in the way the screens were laid out and unfortunately just when I think I can make a blanket statement about a control philosophy, I find one or a dozen anomalies to it." Ex. AT-525 at 1.

1565. Again, an audit showed that "[t]he high number of displayed points may actually reduce the operating safety of the pipeline" and "[t]his setup does little to prevent mistakes that could introduce corrupted data and sounds inconvenient."[810] Ex. AT-408 at 1, 3. J. Martin was critical of UCOS stating: "[b]y definition, the current condition of the UCOS alarms and alarm management system does not meet the minimum requirements for a rational person, using the SCADA system, to accept responsibility for the safe operation of the Pump Station facilities." Ex. AT-523 at 1. Further, he stated that the UCOS system "poses a complex and difficult-to-manage situation which can make a difficult and dangerous situation much worse In a severe alarm flood, the alarm system becomes a nuisance, a hindrance or a distraction, rather than a useful tool for the

[809] Tr. 8596:3-19 (Roberts explaining that prior to SR, there were fewer than 10 screens for the SCADA system, but after SR, the SCADA system had more than 200 screens, and operators experienced failures when trying to open multiple screens).

[810] *See* Ex. AT-406 at 1 ("The big issue is the amount of 'screens' the UCOS platform can have open at one time without bogging down or locking up. I experienced this once when I opened all pump station screens on one runtime and got about a third of the PS09 SR 'dashboards' open before the thing just locked up and wouldn't do anything.").

20140227-3052 FERC PDF (Unofficial) 02/27/2014

operator." "It is well known in the SCADA industry that it is a very common occurrence in the case of serious accidents that the Human Being in control of a SCADA controlled process is 'overwhelmed by the system alarm stream and fails to identify a serious non-expected alarm condition'" Ex. AT-523 at 2.

1566. It is significant that in 2009, recognizing the importance of the controls and alarms to the reliable operations of TAPS, [811] a Project Work Request (PWR) requests funds to optimize the control systems. Ex. AT-412. The document states "[t]he current HMIs are based on historical designs and representation of these systems along with the updates of the SR equipment. The HMIs have not been revised to achieve optimal situational awareness for the controllers and do not reflect current industry recommended practices. The current control system may not allow, or it may be cost prohibitive, to achieve this." *Id.* As the "Justification/Major Drivers" for the request for funds, the PWR states, "[i]t is critical from a safety, environmental, reliability, maintainability, and operability standpoint to ensure that this system provides the necessary information in timely manner and depicts that information in such a manner that provides the OCC Controllers, and other, optimal situational awareness." *Id.* It is found that this is dispositive of the useful prong of the test. After $750 million to among others upgrade control systems, in two years they now are embarking on another upgrade, so what they built is not fit for purpose. *Id*.

1567. The testimony cited by the Carriers that TAPS can be operated without the alarms rather than showing that the new alarm system is used and useful, implies that the alarm system is superfluous. In other words, an alarm system that does not improve on the previous systems and is not necessary to the safe operation of the pipeline is not used and useful. This also contradicts the Carriers statement that "There is nothing more fundamental to the operation of a twenty-first century pipeline than its SCADA system." Carriers RB 155.

1568. SIPPS is "the system that protects the pipeline and has the ability to override all other commands, with the sole purpose of protecting the pipeline." "There's no more critical system to the pipeline than SIPPS." SIPPS was designed with little input form Alyeska personnel who operate it. A SCADA supervisor criticized SIPPS design, "SCADA design elements of SIPPS and the SR project did not follow F370 design concepts and had only minimal input from OCC and SCADA support personnel." [812] Ex.

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[811] Alyeska has recognized that "[i]t is critical from a safety, environmental, reliability, maintainability, and operability standpoint to ensure that this system provides the necessary information in timely manner and depicts that information in such a manner that provides the OCC Controllers, and others, optimal situational awareness." Ex. AT-412.

[812] Koenig supervisor for Conoco's central gathering. Tr. 8715:8-11 (Roberts)(explaining Koenig's background).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

AT-408. The 2010 failure of SIPPS resulted in a shutdown of TAPS. Ex. AT-473 at 2 (an individual Programmable Logic Controller in SIPPS failed). During the failure employees had to be deployed to the field to protect the pipeline. Ex. AT-473 at 3. B. Sullivan testified SIPPs is not working very effectively and that ratepayers are not getting a reasonable benefit for the costs they incurred. Tr. 250:6-12.

1569. All the proper testing of SIPPS still has not been completed. Ex. AT-431 at 30-31. Turnipseed testified that he believed the detailed design of SIPPS is insufficient, which increases the risk within the system. Ex. AT-429 at 15. "[T]he SIPPS detailed design, you will not find that the SIPPS detail design contains sufficient information to interpret or understand what is now installed in the field. You can rely on the cause-and-effects matrices if they're current, but there is not a single SIPPS document that clearly identifies the form and function of SIPPS." Ex. AT-429 at 15 (Tr. 72:15-23).

1570. Turnipseed stated concerning the new equipment: "I have concerns that we haven't identified all the spare parts, I have concerns that we may not have identified sufficient quantities or stocking locations, and I have concerns about obsolescence with parts." Ex. AT-429 at 17. Further, an Alyeska audit memo states "[a]s of April 10, 2007 only 478 line spare items have been stocked as inventory from an estimated 2,700 line items." Ex. AT-507 at 1. Turnipseed also testified "[b]ut we never went to the field and verified that all of the components that would, in time, fail were identified and catalogued and stocked in sufficient quantities to assure their replacement based on, one, their failure rate; and two, their obsolescence. Ex. AT-429 at 18. This testimony shows that the Carriers replaced this equipment not following industry standards.

1571. Carriers arguments about reliability have been addressed above, suffice, they changed the metric and fact is there have been more shutdowns so their claim is not persuasive.

1572. B. Sullivan expressed concerns about system reliability. He testified the system did not have near the false alarms or the shutdowns before SR as are occurring today. Tr. 255:17-23; Tr. 300:13-15 and 17-25. The evidence supports his opinion. Anadarko and Staff are correct that the evidence in this case demonstrates that the number of alarms, UCOS and increased shutdowns, rather than providing benefits, have reduced the benefits already provided by TAPS prior to SR. SR has not provided benefits commensurate with costs. Moreover, rectifying the problems created by SR will create even further costs.

SR did not improve system flexibility in handling various levels of throughput

1573. Anadarko argues that SR has not improved the flexibility, i.e., the range of the throughput of TAPS to handle varying throughput levels. Anadarko argues that the Carriers should not be able to raise the low flow defense for the first time on their November 30, 2012 initial brief. Anadarko RB 102. Anadarko also argues that the Carriers did not present evidence on low-flow argument. Anadarko did enter evidence

20140227-3052 FERC PDF (Unofficial) 02/27/2014

into the record on low flow in support of their position on the life-of-line issue but it was not subject to cross examination because the life-of-line issue settled. Anadarko RB 102-03.

1574. Carriers assert that decision to implement SR was based on an economic analysis that SR would reduce long-run costs associated with the legacy equipment, and that added benefits of SR include right-sizing the pipeline for declining throughput and ensuring efficient, reliable service. Carriers IB 78-79, 207.

Findings/Discussion

1575. Anadarko is correct that the Carriers raise the low-flow benefit of the SR equipment in their initial brief. However, since Anadarko had the opportunity to reply the argument will be considered.

1576. The original design capacity of TAPS without DRA was 1.42 million bpd while the design capacity of SR is 300,000 bpd to 760,000 bpd. Ex. AT-291 at 1787, 1795. In 2003, the Carriers made the decision to reduce the design capacity of TAPS with the SR Project. Ex. AT-291 at 676. The use of DRA increased the original design capacity of TAPS to 2.1 million bpd, while DRA only increases the SR design capacity to 1.14 million bpd. Ex. AT-291 at 676-677, 693.

1577. Anadarko is correct that the Carriers' suggestion that low-flow capability justifies SR is not credible. Un-contradicted evidence shows the legacy equipment was capable of addressing low-flow issues and there was no mechanical or hydraulic lower limit to TAPS. Anadarko's witness Dr. Modisette stated "[t]he TAPS low-flow operational problems are primarily associated with the lower petroleum temperatures due to heat loss in the winter" and "[r]ecirculation removes any *mechanical* lower limit to TAPS flows." Ex. AT-178 at 6 (*see also* AT-22 at 54). Since the legacy equipment provided additional heat and was capable of recirculation, all mechanical low flow limits could have been addressed with the legacy equipment.

1578. Further, the SR Project doesn't address low flow issues unless an additional investment in heaters occurs. Ex. AT-22 at 12. It has also been demonstrated that Alyeska has only investigated low flow issues down to 300,000 bbl/d. [813] Exs. AT-399 at 2; AT-339 at 6-7. These points were also demonstrated by evidence admitted in the prudence phase of the hearing. For example, Carriers' witnesses Howitt and Scott testified regarding the ability of the legacy equipment to run at low flows with the addition of heat. Tr. 6771:1-25 (Howitt); *see* Tr. 5642:7-16 (Scott); Tr. 5643:9-5644:20 (Scott). Further, Carriers' witnesses Howitt and Pomeroy both testified the legacy equipment at PS 7 is currently being used for recirculation in order to add heat to the oil.

[813] In the 20 year planning horizon it is not anticipated that throughput will reach 300,000 bpd. Tr. 232:17-24.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Tr. 6771:23-25 (Howitt); 8116:8-14 (Pomeroy). The record also demonstrates that the SR MLUs may not be operated efficiently at lower throughput levels. These MLUs are not able to operate at current throughput levels without artificially loading the Siemens generators to avoid air quality issues. Tr. 7089:4-9 (Howitt; Tr. 8483:20-23 (Johnson).

1579. The evidence shows that low-flow was not even likely during the planning horizon for SR. Exs. SOA-13 at 7; AT-22 at 10; SOA-136 at 10; AT-230 at 11. Pomeroy stated that Alyeska and the SR team did not conduct an analysis of heat for low flows during the SR conceptual engineering phase. Tr. 8108:21-25. B. Sullivan's and Hisey's testimony in this regard is given significant weight. He testified, "[d]espite this anticipated need for additional heat on the pipeline, I have seen no evidence that the Carriers ever evaluated the potential advantages of utilizing waste heat produced by the legacy turbines prior to replacing that equipment with costly electric driven pumps." Ex. AT-22 at 35. The legacy pump at PS7 has been reactivated to recirculate and heat oil. This could have been done with either PS3, 4 or 1. Tr. 6771:7-20. Hisey testified that the "legacy units create a lot of waste heat. I know there's a theory that you could have used some of that waste heat to put back into the pipeline." Tr. 3720:14-17. The use of heat from the legacy pumps was "looked at" during conceptual engineering but no analysis was done.[814] Tr. 8108:18-25. As B. Sullivan testified, the ability of the legacy pumps to provide heat should have been studied further. Tr. 233:1-7.

1580. In addition, the PS1 White Paper states that the SR equipment configuration provides "poor power system flexibility when operating in decreasing throughput conditions." Ex. SOA-574 at 16. Under this scenario an artificial load will have to be placed on the generators. Ex. SOA-574 at 4. At current throughput and below,[815] the entire load of PS1 is projected to be satisfied without use of the SR Siemens 12.9 MW Cyclone turbine that will be installed as part of SR, because the Cyclone cannot be operated below 60 percent load due to air quality permit restrictions. Ex. SOA-574 at 19. The load projection for the Siemens Cyclones at PS3 and 4 under normal conditions after 2010 shows that the projected load does not exceed 65 percent, and in most scenarios falls below the 60 percent threshold. Ex. SOA-574 at 20-21. Therefore, the evidence shows that the Siemens Cyclones are not "right-sized" for TAPS, since they cannot be operated as throughput declines unless they are artificially loaded, due to air quality requirements. Ex. SOA-574 at 20-21.

1581. Evidence in this case also shows that the new equipment cannot provide low flow capability without the additional expenditure of approximately up to $1 billion in heaters.

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[814] The Reinvestment Strategy Study (January 1999) discussed the possibility of using heat from the legacy equipment.

[815] Howitt testified that current throughput is approximately 550,000 bpd. Tr. 7011:8-11.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Ex. SOA-1 at 66, 71-72.[816] The evidence also shows that the Carriers recently re-started the legacy equipment at PS7 to add heat to the oil. Tr. 4407:21-4408:2. Thus, the conclusion is that SR removal of the legacy equipment removed an existing source of heat. Ex. AT-270; Tr. 5643:9-5644; 6771:23-25; 8116:8-14.

1582. Further, the legacy equipment had more scalability than the current SR equipment. For example, the legacy equipment had a variety of volume levels and peaked at over 2 million bpd in the late 1980s. Ex. AT-22 at 9. BP acknowledged that the legacy equipment could operate at flows at least as low as 300,000 bpd. Ex. SOA-11 at 17. Thus the Carriers assertions to the contrary are not credible. Evidence in this record also indicates that the life of TAPS was "considered virtually unlimited given the execution of appropriate surveillance, maintenance, repair, and replacement programs. Ex. AT-165 at 3.[817] Carrier witnesses Johnson and Pomeroy agreed with this assessment. Tr. 7980:8-19; 8389:19-8390:12. SR removed the highly reliable and flexible legacy equipment and replaced it with equipment with less operability range (300,000 bpd to 1,140,000 bpd).[818] Anadarko is correct, that this reduced the utility of the pumps, since the operability range of the SR equipment is actually less than the range of the legacy equipment.

1583. The record also establishes that the legacy MLUs are more reliable and may be operated more flexibly. To wit, at current throughputs, only two legacy MLUs would need to be operated, whereas five SR MLUs need to be operated to achieve the same positive flow. *See* Ex. AT-490; Tr. 7992:22-7996:19.

1584. B. Sullivan testified that the system is operating today with less throughput than the legacy equipment. Yet the SR system has excessive alarms and more shutdowns. "You are operating today-say it's 550,000 versus the system when it could actually have throughput of 2.1 million. So you're significantly less than that, and it's certainly less taxing on the system to run it at 550,000 barrels a day. So the legacy turbine equipment was extremely robust, and . . . there's a real value to how robust it was and the fact that it could go up to 2.1 million barrels a day. It had a much wider range of operability, and I think that is something that you've lost with the SR equipment." Tr. 362:18-363:2.

SR increased maintenance

1585. Anadarko avers that the addition of the VFDs added complexity and increased maintenance.

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[816] *See also* Tr. 1789:14-22; 3719:2-9.

[817] Ex. SOA-19 (DeHaas explaining Alyeska had many spare Avon units which could provide "zero cost parts" and no immediate problem of obsolescence).

[818] Ex. AT-24; SOA-1 at 65; Tr. 7011:12-16.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Findings/Discussion

1586. Prior to SR, the Avon TG/Cooper RT package directly drove the pump. After SR, the Siemens Cyclone turbine drives a VFD, which then drives the pump. Consequently, SR resulted in an additional piece of equipment for each pump. Ex. AT-490. The evidence in this case shows that the VFDs are maintenance intensive pieces of equipment. Ex. SOA-740 tracks the hours of preventive maintenance estimated to be spent on each piece of equipment at the PSs. For the VFDs, the total hours are 2138.5, this is the highest of any piece of equipment. Ex. SOA-740 at 25-29. Pomeroy testified that he was not surprised the VFDs required so much maintenance. Tr. 8083:14-22. He also testified that the power distribution center was a new piece of equipment required by SR, which was also maintenance-intensive. Tr. 8086:15-25. This evidence shows that maintenance has in fact increased.

Conclusion

1587. For the purpose of used and useful what matters is whether ratepayers have benefited from SR, and the Carriers have not put forth evidence demonstrating that it has. The evidence shows that SR provides no utility to ratepayers. The new pumps (except for PS9) require self-generation of electricity, since the pumps are not near electric grids. The evidence shows that new equipment has not reduced O&M and in fact O&M has increased post-SR. Alarms and shutdowns have increased significantly, a cheap source of heat (legacy pumps) has been taken off the system and the Carriers may have to invest in adding heaters to the pipeline if throughput falls below a certain threshold.

1588. The Carriers have not affirmatively shown that any benefits commensurate to costs have accrued to ratepayers, and thus have not met their burden in demonstrating that the SR project is used and useful. The relevant cases and record evidence indicate that the SR project does not meet the used and useful standard, and neither public policy nor any of the exceptions from our precedent excuses the project from meeting the standard. As, a result, should a finding be made that the project was prudent, the costs of SR should be excluded from rate base based on Commission precedent that the SR equipment although used is not useful.

2. Other ratemaking principles

1589. Anadarko also raises other ratemaking principles to exclude SR costs from rate base. These include: ratepayer benefit, failed project costs, intergenerational equity, and proper allocation of costs between shareholders and ratepayers accomplished through a throughput condition.[819] Anadarko views these principles as separate grounds on which

[819] Staff IB 4 n.2.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

SR project expenses may be excluded,[820] while Staff's position is that recovery may be denied under used and useful but not based on the other principles independently. Staff notes, however, that the intergenerational equity and ratepayer benefit principles lend support to a remedy based on used and useful.[821] Other than used and useful, the Carriers believe the other cost recovery principles are inapplicable here.

1590. As discussed below, these principles are not directly applicable to the SR project and do not provide a separate ground for denying cost recovery in this case. Staff's position is this regard is persuasive.

Ratepayer Benefit

1591. Under the heading of ratepayer benefit, Anadarko contends that to be recovered in rates, costs must produce net benefits to ratepayers, and that benefits must be reasonably related to the cost burden that ratepayers have to bear. Anadarko IB 23. In support, Anadarko cites to cases involving charitable contribution and lobbying expenses to support disallowing costs that do not provide benefits to ratepayers. Anadarko IB 23. Anadarko also cites to cases regarding cost allocation in support of the claim that the proponent of a rate change must demonstrate that costs are roughly commensurate with benefits. Anadarko IB 23.

Discussion/Findings

1592. Anadarko does not provide a clear articulation the ratepayer benefit principle. Anadarko's contention that costs must produce net benefits to ratepayers implies that total benefits must exceed total costs. But this is followed by a more general statement that benefits must be reasonably related to the cost burden that ratepayers have to bear, which does not necessarily require a net benefit. Anadarko IB 23. Since these positions are not the same, and these are not arguments in the alternative, it is unclear exactly what Anadarko is asserting.

1593. Further, the cases Anadarko cites in support for ratepayer benefit are largely inapplicable to SR, as they pertain to Commission exclusion of charitable contribution and lobbying expenses from rate base[822] or do not provide a separate legal ground (from

[820] Anadarko IB 18. Anadarko, however, is not pursuing the throughput claim. Anadarko IB 27. Thus, it is no longer at issue.

[821] Staff RB 71.

[822] *ISO New England Inc.*, 114 FERC ¶ 61,315, at P 13 (2006); *Trunkline Gas Co.*, 90 FERC ¶ 61,017, at 61,064-61,065 (2000); *N. Border Pipeline Co.*, 23 FERC ¶ 61,213, at 61,439 (1983) ("Expenditures incurred to influence the opinion of the public during the selection process have little or no benefit to the ratepayers, and therefore must be borne

20140227-3052 FERC PDF (Unofficial) 02/27/2014

used and useful) for denying recovery. Unlike charitable contribution and lobbying expenses, SR expenses are not among the types of costs that would be categorically excluded, and thus these cases are inapposite. And citations to cases discussing the used and useful principle does not support a separate ratepayer benefit principle and does not add anything not already discussed under the used and useful standard regarding benefits.

1594. For example, Anadarko's quote from *Tennessee Gas Pipeline Co.* is based on used and useful and is not a separate principle: "The Commission has a long-established ratemaking policy of charging construction costs only to those consumers who benefit from the new service. This policy rests upon the 'used and useful' test . . . ." *Tenn. Gas Pipeline Co. v. FPC*, 561 F.2d 955, 957 (D.C. Cir. 1977). Similarly, Anadarko's citation to *Natural Gas Pipeline*, does not help clarify what this ratepayer benefit test is supposed to be. Anadarko IB 189 (citing *Natural Gas Pipeline Co. of Am.*, 27 FERC ¶ 61,201, at 61,379 ("these costs have been disallowed because the projects were found to be speculative and uncertain, remote in time, and without benefit to ratepayers.")). The quoted text is in reference to cases on unsuccessful gas supply projects, and in some of these cases, the cost disallowance was based on used and useful. *Id.* at 61,379 n.7.

1595. While Anadarko's discussion of cost allocation cases may provide insight as to what and how benefits should be considered in a used and useful inquiry (e.g., benefits should be weighed in relation to costs and cannot be too speculative), these cases do not support a separate ground (apart from used and useful) for denying SR project costs. These cases also do not define a clean ratepayer benefit test applicable to the present case, which does not involve cost allocation, but whether costs may be recovered at all through rates.

1596. Given the inapplicability of the cases cited and the consideration of benefits in the prudence and used and useful inquiries, there is no basis or need to invoke a separate ratepayer benefit doctrine.

Failed project

1597. Anadarko, in discussing failed projects, states that failed project costs may be excluded under the used and useful standard,[823] and costs from failed projects undertaken

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by stockholders."); *Alaskan Nw. Natural Gas Transport. Co.*, 19 FERC ¶ 61,218, at 61,428 (1982).

[823] *Koch Gateway Pipe Line Co.*, 68 FERC ¶ 61,189, at 61,955 (1994) ("As a general rule, ratepayers should bear only the legitimate costs of providing service to them, and the Commission generally prohibits recovery of costs for natural gas projects that are not "used and useful" in providing service. Thus, the Commission has long refused to include in regulated rates the costs of failed projects to develop new supplies of natural gas where the projects were speculative and uncertain, remote in time, and without benefit to the ratepayers."); *Columbia Gas*, 13 FERC ¶ 61,102, at 61,222 (1980)

20140227-3052 FERC PDF (Unofficial) 02/27/2014

without advance regulatory approval may not be shifted to ratepayers. Anadarko IB 24-25. But Anadarko does not provide a definition for failed projects anywhere in its briefs[824] (other than to state that the SR "project failed to deliver the promised benefits," (Anadarko IB 209) and thus implicitly defining a failed project to be one that does not deliver promised benefits. But this simply repeats the used and useful argument,[825] and is not a separate ground for denying cost recovery on the basis that the project failed.[826] Under the separate heading of failed project, Anadarko goes on to repeat the same arguments it made in the sections on prudence and used and useful; namely, the project was discretionary, designed to reduce costs, with marginal economic justification, and was motivated in part by improper affiliate considerations and to avoid write-offs. Further the existing equipment was reliable, fit for purpose. Anadarko IB 211-213.

1598. The Carriers advocate a definition that includes as failed projects "only projects that are never constructed, or those that are partially constructed but abandoned before commencing service."[827] There is no reason to confine the definition of failed projects so

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("If a project fails . . . , permitting the pipeline to include its expenditures in its rate base and amortize them through the cost of service would shift the risk from the stockholder to the ratepayer, although the pipeline receives a rate of return to compensate it for business risks. The used and useful principle does not permit the pipeline to shift the risk of loss by imposing the expense of the unsuccessful project upon its current ratepayers who have received no benefit from the project.").

[824] B. Sullivan's testimony (Ex. AT-22) also does not provide a definition for a failed project (other than restating the used and useful standard), and does not provide support for stating that a failed project is one that did not meet its objective. Carriers IB 209 (citing Phase II Tr. 286-287).

[825] Anadarko cites to *Tennessee Gas* and *Columbia Gas*, where costs associated with projects that did not produce any jurisdictional gas were excluded from recovery under the used and useful standard. Anadarko IB 210 (citing *Tenn. Gas*, 606 F.2d at 1123-24; *Columbia Gas Transmission Corp.*, 13 FERC ¶ 61,102 at 61,222). But this does not support a separate failed project rationale for disallowing recovery, but is simply the application of the used and useful standard to exclude project costs that did not provide the intended service, i.e., because the project failed.

[826] Anadarko cites to *Natural Gas Pipeline* in support of disallowing a failed project, but there, the projects at issue were abandoned. Anadarko IB 209-10 (citing *Natural Gas Pipeline Co. of Am.*, 27 FERC ¶ 61,201 at 61,379). That does not justify invoking a separate ground here upon which SR costs are deemed a failed project and excluded.

[827] Carriers cite to *Koch Gateway Pipe Line Co.*, 68 FERC ¶ 61,189 at 61,956 (1994) (applying the failed project doctrine to deny costs where a project was never

20140227-3052 FERC PDF (Unofficial) 02/27/2014

narrowly, but this issue does not need to be decided in this case. (SR has not been abandoned, and SR equipment is being used so it is not straightforwardly a failed project.)

1599. No participant points to an established regulatory definition of a failed project, and the parties' positions appear to represent the broadest and narrowest of the range of plausible definitions. However, since in the cited cases, failed projects are a specific instance of how costs may be excluded under the used and useful standard, and not an independent ground on which to deny recovery, whether SR is a failed project does not need to be determined here, if SR otherwise fails to satisfy the used and useful standard.

Intergenerational Equity

1600. According to Anadarko, under the intergenerational equity principle, current ratepayers should not pay costs for a project that provides them no net benefit. Anadarko IB 25. It also states that the cost burden of a project cannot be imposed on a generation of ratepayers that receives no commensurate benefit. Anadarko IB 213 (citing *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 61,215, at P 18 n.16 (2008) (explaining that "[i]ntergenerational equity is the fair distribution of the costs and benefits of a long-lived project when those costs and benefits are borne by different generations' project users.), *aff'd sub nom. Flint Hills Resources Alaska, LLC*, 627 F.3d 881).

1601. The Carriers claim that intergenerational equity applies only when current shippers receive no benefits from an investment. And that if the investment produces benefits for current and future shippers, carriers may recover costs from current ratepayers, even if some of those costs will only benefit future ratepayers, e.g., recovery of accelerated nuclear decommissioning costs were allowed because this lowered costs for ratepayers as a whole, and the "substantial benefits outweigh both the cost of accelerated recovery and any intergenerational equity that may result from it." Carriers IB 212 (citing *Sys. Energy Res., Inc.*, 96 FERC ¶ 61,165 at 61,742 (2001)).

Discussion/Findings

1602. As argued by Anadarko, the intergenerational equity principle is not distinct from Anadarko's ratepayer benefit principle. Anadarko argues that no generation (neither present nor future) will benefit from SR, so its argument reduces to whether the ratepayers benefit at all. Anadarko IB 214-15. It then repeats the same arguments from its prudence, used and useful, and ratepayer benefit discussions. Anadarko IB 215-16 ("It is purely speculative, and indeed doubtful, that any significant O&M reductions from SR will ever materialize."). Anadarko also cites to a number of cases where costs associated with speculative or unsupported benefits cannot be allocated to current ratepayers

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constructed); *see also Natural Gas Pipeline Co. of America*, 71 FERC ¶ 61,391 at 62,529 (1995) in support. Carriers IB 210; RB 129 n.160.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

(Anadarko IB 214), but those are really about whether the current ratepayers are benefiting, not whether the costs and benefits of a long-live project are fairly distributed between generations.

1603. The Carriers' citation to *System Energy Resources, Inc.*[828] is misleading. The very paragraph cited by the Carriers states that "[d]espite the accelerated payment of decommissioning expenses, the benefits to current ratepayers exceed the costs. While it is true that future ratepayers will also benefit (because they will not be subject to decommissioning expenses . . .) still, current ratepayers could not have obtained the millions of dollars of benefits that the sale/leaseback made (and still makes possible) without the condition that SERI fund decommissioning of the leased portion of the plant on an accelerated basis. We will thus allow accelerated recovery of decommissioning expenses . . . because, in this instance, the substantial benefits outweigh both the cost of accelerated recovery and any intergenerational inequity that may result from it." *Sys. Energy Res., Inc.*, 96 FERC ¶ 61,165 at 61742. In other words the benefits to current ratepayers outweighed the costs to them, and thus, in this instance, accelerated recovery was allowed.

1604. The Carriers also misleadingly quote from *Process Gas*: "it is proper for the FERC to charge existing ratepayers with the costs of a project, the benefits of which all future ratepayers will enjoy." Carriers IB 212-213 (quoting *Process Gas*, 866 F.2d at 476). But the text before and after the Carriers' quote states that: "[i]n certain circumstances, then, it is proper for FERC to charge existing ratepayers with the costs of a project, the benefits of which *all* future ratepayers will enjoy. It is quite another concept, however, to charge existing ratepayers with a cost that not only brings no benefit to them but, rather, may or will imply future detriment." *Process Gas*, 866 F.2d at 476. As with *Process Gas*, to *System Energy Resources*, also uses qualifying language to limit the rule being applied to the particular circumstance.

1605. As argued by Anadarko, the intergenerational equity principle as applied here reduces to whether current shippers benefit from SR, and the Carriers, in cherry picking phrases out of context fail to justify their interpretation of the intergenerational equity principle. Thus, there is no need to consider this principle as a separate ground for excluding SR costs from rates.

Throughput Conditions

1606. No participant advocates using a throughput condition in this case. While a throughput condition was initially raised by Anadarko, they have subsequently recommended against using it in this case. Anadarko IB 26, 217-18. The Carriers also

[828] Carriers IB 212 (citing *Sys. Energy Res., Inc.*, 96 FERC ¶ 61,165 at 61,742 (2001) ("substantial benefits outweigh both the cost of accelerated recovery and any intergenerational equity that may result from it")).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

agree that a throughput condition is not applicable here. Carriers IB 211-12; Carriers RB 130-31. The throughput condition is therefore not at issue here.

B. Issue 2: COST OF SERVICE ISSUES

i. *The 2009 and 2010 cost of service adjustments*

1607. Staff and Anadarko raise various cost-of-service issues related to the Carriers' proposed rate increases to their 2009 and 2010 rates for interstate transportation of crude oil on TAPS.[829] Staff advocates a total cost of service for TAPS of $884.9 million for 2009 and of $861.6 million for 2010. These totals reflect reductions of $43.2 million and $154.4 million from the Carriers' filed cost of service of $928.2 million and $1,016 million for the 2009 and 2010 rate periods. Staff IB 117. Anadarko also urges a cost reduction from the filed rates.[830]

1608. The Carriers, Anadarko, and Staff agree for the most part on using actual costs and volumes for the 2009 and 2010 rate filing base and test periods, as specified below. Anadarko conditions their agreement subject to adjustments in Appendix A of their initial brief, and the Carriers object to Staff's adjustments related to a May 2010 oil spill incident.

1609. For the 2009 and 2010 filings, Staff advocates using actual costs and volumes from October 1, 2008 through September 30, 2009 and from October 1, 2009 through September 30, 2010. Staff IB 117-18. Anadarko adopts Staff's 2009 and 2010 actual costs of service and volumes approach (subject to adjustments in Appendix A of Anadarko's IB) as the basis for the rate calculations (Appendix B of Anadarko's IB). Anadarko IB 280-81, 286; RB 148.

1610. Staff and Anadarko advocate removing, as nonrecurring, oil spill cleanup expenses incurred from June 2010 through September 2010 related to May 2010 oil spill at Pump Station 9.[831] Staff points out that the actual expenses for the twelve months ending September 30, 2010 are exponentially higher than the Carriers' initially filed base period expenses, and the increase in expenses can be attributed to the May 2010 oil spill at Pump Station 9.[832] Staff witness Tran testified that a dramatic increase in expense over a

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[829] The Carriers' interstate rates at issue are summarized in Appendix A to the Carriers' initial brief.

[830] Anadarko adopt Staff's 2009 and 2010 actual costs of service and volumes, subject to adjustments set forth in Appendix A of Anadarko's initial brief.

[831] Exs. S-1 (Tran) at 11-12; S-11 at 7-8; S-17 at 2; Anadarko IB 280; RB 149.

[832] Staff IB 124.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

short time period is usually attributable to an exceptional, nonrecurring event.[833] As this was the case with the oil spill cleanup cost, Staff advocates eliminating it as a nonrecurring item, as required by Commission regulations.[834]

1611. Staff proposes an upward adjustment to volumes moved during the October 2009 through September 2010 test period. Staff IB 133, RB 96-97. Staff witness Cayton testified that he used the most recent twelve months of actual throughput for which data was available in his calculations, and using the latest actual figures up through the end of the adjustment (or test) period is consistent with Commission precedent. Cayton's adjustment to the calculation of TAPS throughput related to an oil spill that shut down TAPS for 80 hours. Staff asserts that this shutdown was a nonrecurring event, and since nonrecurring items must be eliminated, Staff adjusted the throughput upwards to compensate for the time the pipeline was idle. Staff IB 133, RB 96-97.

1612. The Carriers accept Staff's and Anadarko's proposal with respect to interstate volumes, but object to a wholesale update of the cost-of-service data. Carriers RB 175. Carriers concede that Staff's approach has been used in the past but cite to *SFPP, L.P., Op. No. 522*, 140 FERC ¶ 61,220 at PP 18, 41 to support the proposition that a wholesale update is inconsistent with FERC precedent. Carriers RB 175. However, as noted by Staff, the Carriers' interpretation of Opinion No. 522 ignores the fact that the updated cost-of-service was rejected "because such data is not in the record." Staff RB 101 n.336 (citing *SFPP, L.P.*, Op. No. 522, 140 FERC ¶ 61,220 at P 18 n.60) (note that the correct citation should be P 41).

1613. The Carriers accept Staff's and Anadarko's use of actual volumes (246.6 million barrels[835]) for the twelve-month period ending September 2009.[836] The Carriers accept Staff and Anadarko's use of actual volumes during the twelve-month period ending September 2010 (approximately 232 million barrels for the 2010 interstate rates[837]), but disagree with Staff's proposed upward adjustment of approximately 2.2 million barrels for the May 2010 oil spill shut down at Pump Station 9, which Staff and Anadarko claim was a nonrecurring event.[838] The Carriers state that volume levels should be

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[833] Staff IB 124.

[834] 18 C.F.R. § 346.2 (a)(i) (2013) (requiring that cost data used to set rates be adjusted to eliminate nonrecurring items).

[835] Ex. S-11 (Cayton) at 6. Anadarko IB 286.

[836] Carriers IB 271; RB 177

[837] Exs. S-11 (Cayton) at 6-8; S-14 at 1.

[838] Carriers IB 273, RB 178 (citing Anadarko IB 286).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

representative of future throughput, and given the continuing decline in TAPS throughput, Staff's proposed upward volume adjustment makes its proposed volume less representative of future volumes. Carriers IB 274.

1614. The Carriers attempt to justify the oil spill shutdown as a recurring event by pointing to the fact that shutdowns are a common occurrence on oil pipelines, and that there have been planned maintenance shutdowns in all but one of the last 17 years.[839] The Carriers also claim that oil spill cleanup expenses are a recurring cost of doing business in the oil pipeline industry,[840] and that "Alyeska has incurred oil spill clean-up expenses in each of the years 2007 through 2010, and in prior years as well." Carriers IB 281 citing Ex. ATC-656 at 70 (Ganz). Anadarko counters that a shutdown due to an oil spill, unlike planned shutdowns for maintenance or inspection, is not a recurring event, and considering an oil spill to be routine would remove an incentive for pipelines to take greater precautions against oil spills. Anadarko RB 149.

1615. The Carriers acknowledge that oil spills may be considered nonrecurring if the spill is unusual in size or manner of occurrence.[841] However, the Carriers claim that the spill was not unusually large and the cleanup costs were relatively modest. Carriers IB 281.

1616. Alternatively, the Carriers argue that FERC should permit the costs to be normalized and recovered over a reasonable period rather than excluding them entirely. Carriers RB 181. Staff also argues in the alternative that if the Carriers recover for the May 2010 oil spill, it should be through a limited duration surcharge so that these costs do not become embedded in the Carriers' base rates. Staff RB 106.

Discussion/Findings

1617. As the participants recognize, because the actual data for the entire period in this case is available, it is appropriate to use it to set cost of service. Under FERC regulations, a base period consists of 12 consecutive months of actual experience, adjusted to eliminate nonrecurring items. The filing carrier may include appropriate normalization adjustments in lieu of nonrecurring items. 18 C.F.R. § 346.2(a)(i) (2013). A test period consists of a base period adjusted for changes in revenues and costs which are known and are measurable with reasonable accuracy at the time of filing and which

[839] Carriers IB 274 (citing Ex. ATC-656 at 72 (Ganz)).

[840] Carriers IB 281 (citing Ex. ATC-656 at 70).

[841] Carriers IB 281 citing *Amerada Hess Pipeline Corp.*, 117 F.3d 596, 603 (D.C. Cir. 1997) (upholding FERC's determination that costs related to clean-up of Exxon Valdez oil spill should be removed from rates, because the oil spill was an unusual and infrequent occurrence, given its size).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

will become effective within nine months after the last month of available actual experience utilized in the filing. For good cause, the Commission may allow reasonable deviation from this prescribed test period. 18 C.F.R. § 346.2(a)(ii) (2013). As noted by Staff, the Commission approves of using end of test period actual costs rather than filed test period costs as it is the best available data and just and reasonable. Staff IB 120 (citing Ex. S-11 at 7 (lines 2-6)); Staff IB 119 n.278 (citing *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077 (2006) (Commission affirmed Initial Decision, finding O&M expenses as end of test period costs rather than filed period costs is just and reasonable as it is the latest available data)); *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266 (1999) (*citing Williston Basin Pipe Line Co.*, 71 FERC ¶ 61,019, 61,228 **(**1995) (the use of actual data updated for the twelve months ending the day before the rates became effective was the best evidence to use to determine cost-of-service and throughput for the rate period beginning the next day, although those actual amounts could not have been projected with any precision when the pipeline made its rate filing.).

1618. The oil spill expense is appropriately excluded as a nonrecurring item as Staff and Anadarko correctly argue. The Carriers' attempt to justify the spill as recurring by analogizing to planned maintenance shutdowns is unavailing because oil spill shutdowns are unplanned. Further, the Carriers also do not provide a compelling argument for why an oil spill costing up to $10 million to clean up should be considered small enough to be routine. Lastly, sound public policy counsels against allowing the Carriers to include as routine oil spill cleanup costs that, according to the Carriers' estimate, could reach $10 million. The Carriers' assertion (Carriers IB 274) that Staff's proposed upward volume adjustment makes volume level less representative of future volumes is too speculative and unsupported by evidence. Accordingly, Staff's upward volume adjustment is appropriate.

ii. The 2006 supplemental ad valorem tax

1619. At issue is whether the Carriers may include in their 2010 rates a supplemental ad valorem tax payment made in December 2010 for a reassessment of 2006 property tax. A May 24, 2010, Alaska Superior Court decision imposed a supplemental tax of $113.4 million owed on 2006 taxes,[842] and an October 26, 2010, decision determined that the interest owed increased the total supplemental ad valorem tax liability to $154 million. *E.g.*, Ex. ATC-656 at 66-67.

1620. The Carriers made the supplemental ad valorem tax payment under protest in 2010 and have appealed the decision to the Alaska Supreme Court. The Carriers included the supplemental ad valorem tax payment in their 2010 rates. The Carriers only included the principal component of $113.4 million in 2010 rates. Ex. ATC-8 at 67; Ex. ATC-656 at 67 (Ganz).

[842] *E.g.*, Ex. ATC-8 at 67.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1621. Staff and Anadarko seek to exclude this supplemental ad valorem tax payment in rates on the grounds that it would violate the filed rate doctrine, rule against retroactive ratemaking, and intergenerational equity principle; the payment was not known and measurable within the test period; and it is a nonrecurring cost.

The filed rate doctrine, the rule against retroactive ratemaking, and intergenerational equity principle

1622. Anadarko and Staff assert that the recovery of underestimated 2006 ad valorem taxes in 2010 rates violates the filed rate doctrine and the rule against retroactive ratemaking and jeopardize the finality of rates. Anadarko IB 253-259; 270-273; Staff RB 90. The filed rate doctrine forbids a regulated entity from charging rates for its services other than those properly filed with the Commission,[843] and the rule against retroactive ratemaking prohibits the Commission from adjusting current rates to compensate for previous over-or under-recovery of costs in prior periods.[844]

1623. The Carriers assert that the filed rate doctrine and rule against retroactive ratemaking do not bar recovery, because they are not adjusting rates for prior periods, nor are they increasing current period rates to make up for costs that should have been included in prior period rates. Carriers IB 264; RB 164. According to the Carriers, the supplemental ad valorem tax could not have been included in prior period rates, because it did not become "known and measurable" until May 2010, when the Alaska Superior Court issued its reassessment, and October 2010, when the Alaska Superior Court ordered interest be paid. The Carriers argue that the supplemental ad valorem tax payments are a legitimate expense required to provide transportation service on TAPS and could not possibly have been included in past rates. Carriers RB 167-68 (citing *ANR Pipeline Co.*, 89 FERC ¶ 61,244 at 61,723-24 (retroactive ratemaking was not violated where pipeline "could not include" costs in past rates, in part because of a prior FERC ruling and in part because of FERC's "regulations requiring costs to be known and measurable before they are included in rates")).

1624. According to Anadarko, the Carriers knew in early 2006 that the assessed value of TAPS for 2006 ad valorem tax purposes was in dispute[845] and could have in 2006, with

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[843] *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 (1981). *See also Exxon Mobil Corp. v. FERC*, 571 F.3d 1208, 1211 (D.C. Cir. 2009).

[844] *Associated Gas Distrib. v. FERC*, 898 F.2d 809, 810 (D.C. Cir. 1990); *Town of Norwood v. FERC*, 53 F.3d 377, 381 (D.C. Cir. 1995); *Williston Basin Interstate Pipeline Co.*, 55 FERC ¶ 61,340 (1991).

[845] The record reflects that the lien date for TAPS for tax purposes was January 1, 2006; the Alaska Department of Revenue made a determination of the value of TAPS, which was appealed to the SARB; and the SARB held a hearing in May 2006 on the appeal. *See* Ex. AT-6 at 5, P 3, 20, PP 48-49 (Amended Decision).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

proper notice to shippers, sought regulatory approval to recover or preserve their right to recover the additional tax payments for 2006 in the future. Anadarko IB 257; Staff IB 126. In support, Anadarko cites to *Town of Norwood*, where the court held that it would not constitute retroactive ratemaking if the ratepayers had notice that the charges would be collected in the future. *Town of Norwood v. FERC,* 53 F.3d 377, 383 (D.C. Cir. 1995). Anadarko points out in *Town of Norwood*, the company had "not shifted any costs that it tried but failed to collect in the past: it *always* planned to collect these costs from future ratepayers, the only shift is timing within the future." *Id. at* 381 (emphasis in original). Anadarko contends that the Carriers cannot credibly claim they always planned to collect additional amounts due for 2006 taxes from future ratepayers. AT RB 140. At any rate, there is no evidence in this case that the Carriers gave notice to ratepayers that the Carriers would attempt to collect 2006 ad valorem taxes in future rates. Anadarko IB 258-59; Staff RB 91.

1625. The Carriers attempt to overcome the filed rate doctrine and rule against retroactive rulemaking by insisting that the 2006 tax liability only became known and measurable in 2010 and that the 2010 rates prospectively reflect the supplemental ad valorem taxes paid in December 2010. The Carriers assert they are not proposing to charge anything other than rates on file or to recover costs that should have been, but were not, included in prior period rates. According to the Carriers, the fact that the payment "relates" to a prior tax year does not mean the retroactive ratemaking doctrine is violated by including what they deem a 2010 payment in 2010 rates. Carriers RB 172.

1626. As to notice, the Carriers assert that the 2010 rates include the supplemental ad valorem tax payments and shippers in 2010 had notice of this fact when making their decisions to transport oil under the 2010 rates. Carriers RB 165-70. Carriers also note that the appeal of the 2006 ad valorem tax assessment has been public knowledge since May 2006, when the Alaska State Assessment Review Board held a hearing on the appeal. Carriers RB 171 (citing Ex. AT-6 at P 49). According to the Carriers, Anadarko's counsel represented municipal parties in the ad valorem tax case and thus Anadarko cannot claim to not have actual notice of the ongoing ad valorem tax appeal. *Id.* at 171.

1627. As to expenses that relate to prior periods, the Carriers attempt to justify including the 2006 supplemental ad valorem tax in 2010 rates by citing to Commission precedent approving settlement payments involving events arising in prior years as costs properly included in current rates. Carriers RB 167 (citing *PUC of Cal. v. FERC*, 988 F.2d at 161 (explaining that settlement costs "incurred to extinguish take-or-pay liabilities that accrued in the past … are nonetheless current costs" and their inclusion in current rates "is not barred by the filed rate doctrine or the prohibition against retroactive ratemaking"); *Transwestern Pipeline Co.*, 73 FERC ¶ 61,091 at 61,280-81 (costs to settle take-or-pay issues related to past periods are current costs that are appropriately included in current rates without violating the rule against retroactive ratemaking)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1628. Anadarko contends that asking current shippers to pay costs relating to shipping in 2006 violates the intergenerational equity principle. Although the identity of the shippers may be the same, Anadarko notes that there is no record evidence on the shippers and amounts each ship, which may not be the same in 2006 versus today, and thus asking current shippers to pay for 2006 shipping costs would result in a mismatch between service received and costs borne. Anadarko IB 267-68. Anadarko also points out that the surcharge proposed by the Carriers does not solve the intergenerational equity problem. Anadarko IB 268.

1629. The Carriers attempt to address the intergenerational equity problem by contending that paying the supplemental ad valorem tax benefits current shippers because the Carriers need to pay their ad valorem taxes as they come due in order to continue to provide transportation service to current and future shippers. Carriers RB 172. The Carriers emphasize that the surcharge is not imposed on barrels that moved prior to 2010, and that shippers had notice that the supplemental ad valorem tax was included in the 2010 rates. According to the Carriers, by spreading the costs over a period (which they proposed to be three years) would be fully consistent with the intergenerational equity principle as current and future shippers benefitting from the transportation service made possible in part by the Carriers' payment of their ad valorem tax obligations would pay the surcharge. Carriers RB 174.

Discussion/Findings:

1630. The parties do not dispute that the filed rate doctrine and the rule against retroactive ratemaking bar the Carriers from altering 2006 rates or including in current rates expenses properly included in 2006 rates. It is well established, the filed rate doctrine forbids a regulated entity from charging rates for its services other than those properly filed with the Commission.[846] Related to the filed rate doctrine is the rule against retroactive ratemaking, which prohibits the Commission from adjusting current rates to compensate for previous over-or under-recovery of costs in prior periods.[847] The

[846] *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 (1981). *See also Exxon Mobil Corp. v. FERC*, 571 F.3d 1208, 1211 (D.C. Cir. 2009); *Transwestern Pipeline Co. v. FERC*, 897 F.2d 570, 577 (D.C. Cir. 1990) (filed rate doctrine allows customers "to know in advance the consequences of the purchasing decisions they make").

[847] *Associated Gas Distrib. v. FERC*, 898 F.2d 809, 810 (D.C. Cir. 1990); *Town of Norwood v. FERC*, 53 F.3d 377, 381 (D.C. Cir. 1995); *Williston Basin Interstate Pipeline Co.*, 55 FERC ¶ 61,340 (1991). Note that this rule is not as limited as the Carriers make it out to be by selectively quoting from *Town of Norwood*: "[o]nly if the [regulated entity] is … attempting to make up for errors in earlier approximations of actual costs, does it engage in impermissible retroactive ratemaking." Carriers RB 170 (citing *Town of Norwood*, 53 F.3d at 383). The full text indicates that this statement applies to the particular situation and does not limit retroactive ratemaking in this way.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

retroactive ratemaking doctrine thus prohibits the Commission from doing indirectly what it cannot do directly.[848] Both doctrines aim to prevent adjustments from rendering current rates unreasonably high or low.[849]

1631. The Carriers' attempt to overcome these bars by asserting that the 2006 supplemental ad valorem tax is properly included in 2010 rates because the tax liability allegedly became known and measurable in 2010. Given that the 2006 rates underestimated the tax liability, making up this difference in 2010 rates means that 2010 shippers are paying for an expense 2006 shippers should have paid. Requiring 2010 shippers to pay costs from 2006 violates the intergenerational equity principle, unless of course the shippers in 2006 and 2010 are identical and shipped the same volume in both years. But if the current shippers are identical to 2006 shippers, including the 2006 supplemental ad valorem in current rates effectively constitutes retroactive ratemaking because the Carriers are charging the 2006 shippers at a later date for a 2006 under-recovery. The Carriers argue that the 2006 supplemental ad valorem tax is not a rate imposed on barrels moved in 2006, and thus folding the payment into 2010 rates is not retroactive ratemaking. But allowing the Carriers to relabel under-recovered taxes from 2006 as a 2010 expense is to allow them to do indirectly what they cannot do directly: recover costs that were underestimated in 2006 on a later date.

1632. The Carriers claim that there was no possible way for them to include the 2006 supplemental ad valorem tax payment in 2006 rates. This is not true – as noted by Staff and Anadarko, the Carriers could have preserved their right to collect by seeking regulatory approval to collect on a future date and by providing notice to ratepayers that they would do so. As noted by Anadarko, the *Town of Norwood* court found it "permissible for a company to *defer* collection of certain charges until the point at which they become ascertainable, so long as the ratepayers have notice that the charges will be collected in the future." *Town of Norwood v. FERC*, 53 F.3d 377, 383 (D.C. Cir. 1995). Further, the company was deemed to be collecting future costs from future ratepayers, because it "has not shifted any costs that it tried but failed to collect in the past: it *always* planned to collect these costs from future ratepayers, the only shift is timing within the future." *Town of Norwood v. FERC*, 53 F.3d 377, 381 (D.C. Cir. 1995) (emphasis in original). The record in this case does not show that the Carriers made an attempt in

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[848] *Associated Gas Distrib.*, 898 F.2d at 810.

[849] *Pub. Utils. Comm'n of Cal. v. FERC*, 988 F.2d 154, 161 (D.C. Cir. 1993); *Associated Gas Distrib.*, 898 F.2d at 810; *Southern Cal. Edison Co. v. FERC*, 805 F.2d 1068, 1070 at n.2 (D.C. Cir. 1986); *Exxon Mobil Corp.*, 571 F.3d at 1211 ("FERC may not retroactively alter a filed rate to compensate for prior over- or underpayments."). *Exxon Mobil Corp.*, 571 F.3d at 1215 (Limiting refunds to be paid to independent power generators for overcharges to interconnect to utilities' electric transmission systems).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

2006 to notify ratepayers that they would defer collection of the supplemental ad valorem tax or to seek regulatory approval to do so.

1633. Additionally, the Carriers citations to Commission approval of settlement payments involving events arising from prior years to justify including tax payments properly attributed to prior years is inapposite because settlement payments, unlike ad valorem taxes, cannot be estimated using the tax assessment for the appropriate year and incorporated into rates.

The 2006 supplemental ad valorem tax payment was not known and measurable within the applicable base and test period

1634. At issue is whether the $113.4 million supplemental ad valorem tax payment is properly included in the applicable period as a known and measurable expense.[850]

1635. The Carriers argue the 2006 supplemental ad valorem tax payment was properly included in their 2010 test period, because the tax liability became known and measurable when the Alaska Superior Court issued its order on May 24, 2010, which was during the nine-month test period ending on September 30, 2010. According to the Carriers, when a tax obligation arises during the test period, the expense is known and measurable even though the payment is made after the end of the test period. Carriers IB 259-61; RB 158-59 (citing *Enbridge Pipeline (KPC)*, 100 FERC ¶ 61,260, at P 306 (2002)). The Carriers argue that FERC regulations do not require actual payment to be completed before the end of the test period, "so long as a contractual obligation for the costs was incurred during the test period," and the "issuance of the tax bills during the test period created an obligation to make the tax payments[.]" *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 306. Carriers assert that this proposition can be extended from the situation in Enbridge, where a portion of the payment is made before the end of the test period to where the entire payment is made after the test period.

1636. Carriers maintain that the obligation to pay $113.4 million was known and measurable as of the May 24, 2010 order, not as of the October 26, 2010, Alaska Superior Court amended decision (which would be outside of the 2010 test period). Carriers point to the fact that they included $113.4 million in their rate filings made prior to October 26, 2010 amended decision. Carriers RB 161 (citing Ex. CPT-14 (Falcone) at 18-19 (testimony in support of CPTAI's 2010 intrastate tariff filing submitted on July 23, 2010, referencing inclusion of the $113.4 million supplemental ad valorem tax liability)); Carriers IB app. A (showing that each of the Carriers' 2010 interstate rates was filed prior

[850] The interest on the December 2010 payment for the 2006 taxes was not included in 2010 rates, because it "did not become known and measurable until October 2010," and that "potential change in the ad valorem tax for 2006 that may result from the TAPS Carriers' protest and appeal is not known and measurable so that it should not be reflected in the current cost of service." Ex. ATC-656 at 67 (Ganz).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

to October 26, 2010). Carriers assert the October 26, 2010, decision did not change the ad valorem tax assessment, but simply added the requirement to pay interest. Carriers RB 161 (citing Exs. ATC-656 (Ganz) at 66; CPT-1 (Falcone) at 14; EM-1 (Ray) at 10-11). [These sources do not state or imply that the decision simply determined the interest, and the Carriers did not cite to the decision itself.]

1637. Staff and Anadarko argue that the 2006 supplemental ad valorem tax payment should be excluded from the Carriers' 2010 rates because the payment was not made until December 2010, after the test period, which ended on September 30, 2010. Further, the payment was made under protest and appealed, and thus not known and measurable within the test period. Staff IB 126-28, RB 87; Anadarko IB 260-62.

1638. According to Staff and Anadarko, FERC limits recovery to ad valorem taxes actually paid during the test period.[851] Anadarko IB 266 & n.1274; Staff IB 126-28. As noted, Carriers attempt to counter this proposition by citing to *Enbridge Pipelines*,[852] but Anadarko points out that in *Enbridge*, the taxing authority must issue the tax bills during the test period, and tax payments must at least commence during the test period for ad valorem taxes to be included in the test period for these costs to be known and measurable. *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 306. Anadarko RB 139.[853]

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[851] FERC "generally requires use of actual test period *ad valorem* tax payments to determine the *ad valorem* tax expense to include in a pipeline's rates." Anadarko IB 266 quoting *Williston Basin Interstate Pipeline Co.*, 87 FERC ¶ 61,265, at 62,024 (1999).

[852] Carriers state that "FERC has made clear that when a tax obligation arises during the test period, the expense is known and measurable even though the payment is made after the end of the test period." Carriers RB 158 (citing *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 306 (2002)).

[853] Staff also distinguishes *Enbridge* from the instant case: the ad valorem payments in *Enbridge* were for the current tax year, whereas the Carriers' payment is for the 2006 tax year with recovery sought in 2010 rates. Also, the ad valorem tax in *Enbridge* was for a defined period and not under appeal, which allowed the Commission to view the obligation as "known and measurable." Staff IB 128-29, RB 88 (citing *Enbridge Pipelines*, 100 FERC ¶ 61,260 (2002)). Ad valorem tax bills for a full year straddled the test period at issue in that case. The pipeline sought to project its tax costs with payments of about half of its taxes for one year and accrued liability for the other half. The Commission accepted the pipeline's proposal even though the pipeline did not make a complete payment in the test period of the projected amount. The Commission determined that "[t]he assessments provide a means by which the 1999 ad valorem taxes became known and measureable." *Id.* at 61,981. By contrast, the Carriers' contractual obligation is subject to change after the end of the test period depending on the outcome of their appeal of the Superior Court determination. The Carriers cannot shoehorn the

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1639. Anadarko points out that not only was the tax payment in December 2010 outside of the test period (which ended on September 30, 2010), but the supplemental tax assessment also occurred after the end of the test period, and both were required in *Enbridge* to include the additional tax payment in the test period. While the Carriers reference the May 24, 2010 Alaska Superior Court decision as making the additional 2006 tax payment known and measurable,[854] on reconsideration,[855] the court amended its decision on October 26, 2010,[856] and entered a final judgment for the 2006 tax year[857] and provided that the "matter will be remanded to the Department of Revenue for the issuance of a supplemental certified assessment roll . . . ."[858] Anadarko thus claim that the Amended Decision only sets forth the basis for determining the 2006 taxes, and the supplemental tax assessment on TAPS for the 2006 tax year did not occur until after the October 26, 2010, decision. Anadarko IB 265-66; RB 142.

1640. Staff and Anadarko contend that the tax payment made under protest and under appeal is *not* known and measurable with reasonable accuracy within the test period, because the Alaska Supreme Court could uphold, reverse, or remand the superior court decision, resulting in a variety of outcomes in terms of the tax liability. Staff IB 128; RB 94 citing Ex. AT-42 at 14 (Brown); Anadarko IB 264-65. Staff witness Tran stated that "[g]iven that ad valorem taxes are commonly protested and appealed, there is no assurance as to the actual amount of these taxes until they are paid." Staff IB 129 (citing Ex. S-1 at 13-14 (Tran)). Staff notes that the Carriers may receive a partial refund of their December 2010 tax payment, and because a company is not obligated to flow

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facts of their case into *Enbridge* to justify including payments made entirely outside of the test period; doing so stretches the precedent in too many ways. Staff IB 128-29.

[854] Ex. ATC-8 at 67; Ex. ATC-656 at 67 (Ganz). Ganz concedes that in May 2010, the Carriers did not even know if the additional 2006 tax payment would bear interest. Ex. ATC-656 at 67 n.28 (Ganz). Neither the Carriers nor any other party made the May 24, 2010, decision an exhibit in this case, and the Carriers' witnesses referencing the May 24, 2010, decision do not specify how that decision relates to actual additional taxes on TAPS. Anadarko RB 141.

[855] Ex. AT-6 at 4 (Amended Decision).

[856] Ex. AT-6 at 171 (Amended Decision).

[857] Ex. AT-6 at 4 (Amended Decision).

[858] Ex. AT-6 at 171, P 511 (Amended Decision).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

through any tax refund,[859] Carriers should not receive an adjustment for a payment that is subject to at least partial refund. Staff IB 128.

1641. At to the uncertainty due to appeal, the Carriers position is that while the $113.4 million supplemental ad valorem tax liability is known and measurable, any possible future changes to the ad valorem tax liability arising from appeal are not. The Carriers state that if the liability is later changed as a result of appeal, an adjustment can be made when it occurs. Carriers offer an example from *SFPP, L.P.*, where FERC approved a pipeline's inclusion of increased state property taxes in rates despite an ongoing appeal on the condition that if the pipeline prevailed in its appeal, the increase would be removed from cost of service and any tax refund received would be distributed to shippers. Carriers IB 265; RB 163 (citing *SFPP, L.P.*, 113 FERC ¶ 61,277 at P 99 (2005)). The Carriers, however, offer no explanation for why this same reasoning or recovery mechanism could not have applied in 2006.

1642. Staff does not agree with the Carriers that *SFPP, L.P.* allows for a refund if the Carriers prevail on appeal (Carriers IB 265). Staff points out that

> The issue in SFPP was not the property assessment, or challenging the State of Arizona's standards or conclusions in making the assessment, but whether the extra $4 million should be included in SFPP's cost-of-service in light of the Commission's prior conclusion that. . . [SFPP's] 1998 PPA [Purchase Price Adjustment] should not be used in designing the pipeline's rates. In this case the Commission will permit SFPP to include the additional $4 million in additional real estate taxes in its cost-of-service because it is an out-of-pocket cash expenditure with one condition. The condition is that if SFPP prevails in its appeal of the assessment in the state proceedings, the $4 million must be removed from its cost of service (or adjusted to such lower amount as might result), and any tax refund distributed to its shippers.

SFPP, L.P., 113 FERC ¶ 61,277 at P 99. Staff distinguishes SFPP on the basis of (1) PPAs are not in issue; (2) the fact pattern addressed was specific to SFPP and application of a prior *SFPP, L.P.* order; and (3) the out of test period, ad valorem taxes in this case are not present in *SFPP, L.P*. Staff RB 94 n.302.

Discussion/Finding

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[859] Staff IB 127 (citing *Williston Basin*, 76 FERC ¶ 61,066 at n. 21). Even where the Commission has permitted an adjustment for ad valorem taxes, it has required that the tax be paid in the test period. *Portland Natural Gas Transmission System*, 134 FERC ¶ 61,129 at P 100 (2011).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Changes pursuant to ERRATA of 3/7/14.

1643. Commission regulation allows only expenses known and measurable within the applicable period to be included in rates. Commission precedent interprets known and measurable to mean that the tax bill is issued and paid (or payments have commenced) within the applicable period. As pointed out by Anadarko, the *Enbridge* court explained that

> costs are known and measurable if they become known with reasonable accuracy at the time of the filing and will become effective within the adjustment period. The Commission has held that this regulation does not require actual payment to be completed before the end of the test period, so long as a contractual obligation for costs was incurred during the test period. Here the state's issuance of tax bills during the test period created an obligation to make the tax payments in the amount claimed by KPC, and payment commenced during the test period with the payment of the first installment. There is no need to speculate on how the taxing authorities might modify their existing test period appraisal of the value of KPC's properties, as in *Northwest* and *Williston*. This is sufficient to treat the 1999 tax assessments as known and measurable amounts that are appropriate for cost of service ratemaking.

Enbridge Pipelines (KPC), 100 FERC ¶ 61,260, at P 306 (footnotes omitted).

1644. There is no compelling rationale in this case to extend this precedent to include payments made outside of the applicable period. Here, the Carriers did not make the payment in the test period and assert that simply having the tax assessment is sufficient. But their argument raises the question of why the same logic cannot be applied to the Carriers situation in 2006. The tax liability was in dispute in 2006, as it is now (under appeal), without the payment requirement, the 2010 Superior Court decision does not render the tax liability ay more certain than it was in 2006.

Thus, without the requirement that the tax payment be made within the applicable period, the Carriers' argument that the 2006 supplemental tax liability only became known and measurable through a 2010 court decision,* but the amount assessed in taxes in 2006 was not known and measurable is inconsistent.

1645. Moreover, since the supplemental payment is for 2006 taxes it really does not matter for 2010 rates when the liability became known and measurable. The only Carriers remedy had to have been sought in the 2006 rate filing. The tax liability and its potential increase was known at that point in time.

2006 supplemental ad valorem tax liability is not a recurring cost

1646. At issue is whether the $113.4 million supplemental ad valorem tax payment is properly included in the applicable period as a recurring expense.

* Affirmed by *BP Pipelines (Alaska) Inc. v. State, Dep't of Revenue*, Nos. S -14095, S -14116, S -14125, 2014 WL 685986, at 17 (Alaska, Feb. 19, 2014). This Alaska Supreme Court decision, however, does not alter the conclusion in paragraph 1653 of the Initial Decision that the tax "payment was not known and measurable and did not take effect within the test period" because the Alaska Supreme Court decision was issued outside of the applicable period.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1647. The Carriers argue that supplemental ad valorem tax obligations have been recurring costs in recent years and are likely to remain so for the foreseeable future. Carriers IB 266; RB 173. Carriers point to a December 30, 2011, Alaska Superior Court decision upholding an increase in the ad valorem valuation of TAPS for the 2007 through 2009 tax years. Ex. AT-286 at 215-16. The 2010 assessment has also been appealed, which may lead to additional supplemental ad valorem tax liability. *See* Ex. ATC-656 at 66 (Ganz).

1648. Anadarko and Staff assert that the 2006 supplemental ad valorem tax payment is not a recurring cost and thus must be excluded from rates even if the payment was made within the applicable period. Anadarko IB 262; Staff RB 92. *See Williston*, 104 FERC ¶ 61,036, at P 69 ("'[W]e may adopt test period estimates, or other, more representative figures of historical costs such as updated actual figures if we determine that these other figures are the best most representative evidence of the pipeline's experience for the test period.' We find that the MMS payment . . . is nonrecurring, and therefore not representative of the pipeline's cost to provide service during the period the proposed rates are in effect."). *See also Tarpon Transmission Co.*, 59 FERC ¶ 61,241, at 61,820 (1992) ("Commission practice is to permit the pipeline to recover only those prudent costs which the pipeline projects it will incur in the future. Normal or recurring operating expenses are based on test period expenses. . . . [I]f a cost is not one that is expected to recur as part of its ordinary recurring cost of service, the Commission's regulations provide that the pipeline is *not entitled* to recover that cost even if it falls within the test period.").

1649. While the Carriers argue that the increase in the ad valorem valuation of TAPS for the 2007 through 2009 tax years supports that the 2006 supplemental ad valorem tax payment is a recurring cost, Anadarko points out that the gap between the SARB valuation and the Alaska Superior Court is narrowing.[860] Additionally, Anadarko states that the trend has been for lower additional taxes on TAPS, and assuming the Carriers will have a recurring additional tax liability of $113.4 million per year would not accurately represent the pipeline's experience for the applicable test period going forward. Anadarko RB 143.

1650. Anadarko argues that treating the 2006 additional tax payment as recurring will embed it in rates, which will factor in an amount equal to the 2006 additional payment for each year that rate remains in effect, even when the Carriers have not made such

[860] Anadarko states the Alaska Superior Court increased the value of TAPS by approximately $5.6 billion for the 2006 tax year, by $4.3 billion for the 2007 tax year, by $3.49 billion for the 2008 tax year, and by $200 million for the 2009 tax year. Anadarko RB 143 (citing Ex. AT-6, Amended Decision Upon Reconsideration Following Trial De Novo at P 51, P 510; Ex. AT-286, Decision Following Trial De Novo at P 38, P 41, P 45, P 599).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

additional payments. Anadarko RB 142. The Carriers counter that with nonrecurring expenses, FERC's regulations permit "appropriate normalizing adjustments in lieu of non-recurring items." Carriers IB 266; RB 173 citing 18 C.F.R. § 346.2(a)(1)(i) (2013). Thus, the Carriers alternatively request recovery of their supplemental ad valorem tax payment by amortizing it over a reasonable period (such as three years) or through a surcharge and point to instances where the Commission has approved surcharges for unusual and extraordinary expenses. Carriers IB 266-67 (citing *SFPP, L.P.*, 111 FERC ¶ 61,334 at P 47 (2005) (SFPP to recover unusually large, nonrecurring legal expenses through the use of prospective surcharges that expire once the expenses are recovered. This was litigation that SFPP did not commence, and to that extent did not have control over the timing of incurred expenses); *Chevron Pipe Line Co.*, 115 FERC ¶ 61,117, at P 31 (2006) (finding a surcharge appropriate for extraordinary hurricane-related expenses); *Extraordinary Expenditures Necessary to Safeguard Nat'l Energy Supplies,* 96 FERC ¶ 61,299 at 62,129 (2001) (establishing surcharge for recovering additional security costs following September 11, 2001 terrorist attacks); *SFPP, L.P.*, 118 FERC ¶ 61,267 at P 6 (2007) (approving surcharge to recover the costs of complying with certain ultra-low sulfur diesel regulations)).

1651. Staff and Anadarko argue against a surcharge**,** pointing out that the purpose of a surcharge is to allow recovery of legitimate, extraordinary cost items, but ad valorem tax assessments do not constitute extraordinary, unforeseeable events. Staff RB 93 (citing *SFPP, L.P.*, 111 FERC ¶ 61,334 at P 50 (2005)). Rather, ad valorem taxes are standard for a pipeline's cost of service, and estimates of ad valorem taxes are included in proposed rates based on a test period. A cost estimate may be too high or low, but Carriers are not allowed to piecemeal their costs of service to ensure a complete recovery, nor are they required to refund an over-collection when a cost is lower than estimated. Anadarko RB 144. Anadarko argues the Carriers have not justified a surcharge, and the cases they cite show that surcharges are imposed to recover costs (for extraordinary events) not otherwise included in indexed rates. But TAPS is not subject to indexing, and Anadarko's position is that cases cited by the Carriers based on whether a particular cost at issue was included in indexing or should be recovered in a surcharge are irrelevant to TAPS. Anadarko RB 145.

Discussion/Finding

1652. The 2006 supplemental ad valorem tax liability is not a recurring cost, and embedding it in rates would render future rates less representative of actual costs of service. A surcharge is also inappropriate, an additional tax liability due to a tax underestimate, is not an extraordinary event. Allowing a surcharge under this circumstance would allow Carriers to recover underestimates through a surcharge but leave shippers at risk in the event of an over-recovery from an over-estimate of taxes.

Conclusion

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1653. Accordingly, for reasons mentioned above, the 2006 supplemental ad valorem tax payment cannot be included in 2010 rates on the grounds that it would violate the filed rate doctrine, rule against retroactive ratemaking, and intergenerational equity principle; the payment was not known and measurable and did not take effect within the test period; and it is a nonrecurring cost.

1654. It merits reiterating that the Carriers were not without a means to recover their tax liability in the 2006 rate filing. The Carriers had a tax assessment when they filed their rates for the 2006 tariff and knew since 2005, the State wanted to change the methodology for valuating TAPS. *BP Pipelines (Alaska) Inc., et al. v. State of Alaska Department of Revenue, et al.*, Case No. 3AN-063-08446 CI (Consolidated) (Alaska Super. Ct. Dec. 30, 2011) at PP 27-35. The Carriers could have consulted the Commission and notified the ratepayers regarding their intention to recover any additional tax liability pending the resolution of the 2006 ad valorem dispute. As there is no evidence in the record that the Carriers have done so or taken any other steps to preserve their rights in 2006 to collect in the future,[861] their proposed resolution is inconsistent with the filed rate doctrine, rule against retroactive ratemaking, intergenerational equity, and Commission policy.

iii Litigation expenses

1655. The Carriers propose a three-year surcharge to recover litigation costs. The Carriers 2008 and 2009 base period rate litigation costs ($2.9 million and $5.1 million, respectively), are significantly lower than the Carriers' average annual regulatory costs in recent years ($11 million in 2005, $14.3 million in 2006 and $8.3 million in 2007). According to the Carriers, to obtain a representative level of ongoing rate litigation expense, they used the average of the annual costs incurred during the four-year period from 2005-2008 (approximately $9.1 million). The $9.1 million amount approximates the average annual costs incurred during the 2005-2006 rate case and likely underestimates the annual level of rate case litigation costs to be incurred in the current litigation, but is more representative of the costs that the Carriers are likely to incur than simply using the actual FERC rate litigation costs incurred during the 2008 and 2009 base period. Alternatively, the Carriers propose the $9.1 million as a normalized level of regulatory litigation expense. Carriers IB 277, 279; RB 179. The Carriers aver that Staff's and Anadarko's proposals are unreasonably low. According to the Carriers for this litigation in the year 2010 they spent $14.5 million. Carriers IB 277-78 (citing Ex. ATC-656 at 43 ($11 million in 2005, $14.3 million in 2006, and $8.3 million in 2007); Ex. S-3 at WP 7 ($14.5 million in 2010)).

1656. Staff advocates replacing the Carriers' proposal with actual Commission rate case litigation costs amortized over a three-year period: 2007-2009 and 2008-2010 for 2009 and 2010 rate cases, respectively. Staff asserts that this approach is more representative

[861] *See, e.g.*, 18 C.F.R. § 352 (2013).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

of costs in rate years 2009 and 2010 and consistent with Commission precedent. Staff RB 101-04. This results in $5.4 million and $7.5 million for each rate period. Staff IB 131. This adjustment removes approximately $6.252 million and $4.032 million form the Carriers filed test period adjustments.[862] *Id.* Staff seeks to exclude the amounts proposed by the Carriers that are outside the rate periods as speculative, out-of-test period projections. Staff IB 132.

1657. Anadarko adopts Staff's approach outlined above[863] and concurs with Staff's adjustments to litigation expenses. Anadarko also states that adopting Staff's allocation of litigation costs between FERC and RCA jurisdictions addresses Anadarko's issue with the Carriers' allocation of litigation costs between jurisdictions. Anadarko IB 285-86 (citing Ex. AT-42 at 18-19 (Brown)); Anadarko RB 147-48.

Discussion/Finding

1658. Staff's approach of amortizing over three years corresponding to the 2009 and 2010 rate periods is consistent with Commission precedent. As Staff asserts, amortizing the TAPS rate case litigation expense over three years is not only consistent with Commission base-and test-period ratemaking methodology (addressing only the rate periods at issue in the proceeding) and addresses the year-to-year variation in litigation expenses, consistent with Commission precedent. Staff witness Tran's testimony in this proceeding is given significant weight. Tran calculated the FERC litigation expenses from 2007-2010 using only the actual costs for the twelve months comprising each year.[864] The ongoing nature of TAPS litigation warrants normalizing litigation expenses and use of the average of the TAPS Carriers most recent three years of regulatory expense. Moreover, as Staff points out, three years normalization is more representative of costs in rate years 2009 and 2010. As a result, Staff proposal is adopted. *SFPP, L.P.*, Op. No. 522, 140 FERC ¶ 61,220, at P 80 (2012) (amortizing litigation expenses over a three-year period); *SFPP, L.P.*, 134 FERC ¶ 61,121, at P 35 (2011) (amortizing litigation expenses over a three-year period); *Williston Basin Interstate Pipeline Co.*, 84 FERC ¶ 61,081, at 61,364-66 (1998) (directing a three-year amortization period for rate case expenses); *Tarpon Transmission Co.*, 58 FERC ¶ 61,354, at 62,183 (1992) (directing a three-year amortization period for rate case expenses); *Kuparuk Transp. Co.*, 55 FERC ¶ 61,122, at 61,384 (1991) (amortizing litigation expenses over a three-year period). *See also Portland Natural Gas Transmission Sys.*, 134 FERC ¶ 61,129 at P 110-111 (2011)

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[862] Exs. ATC-16, Workpaper 10 at 1; ATC-17, Workpaper 10 at 1.

[863] Ex. S-1 at 14-15 (Tran); Ex. AT-42 at 20-21 (Brown). Anadarko IB 285.

[864] Tran disagreed with the years used by the Carriers to calculate their litigation expense and the choice to use end-of-test-period actuals for 2008. According to witness Tran, the test period ended in September 2009, and thus the Carriers included costs outside their 2005-2008 range. Ex. S-1 at 10.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

(directing removal of rate case expenses incurred outside test period); *Williston Basin Interstate Pipeline Co*., 107 FERC ¶ 61,164 at P 68 (2004) (directing exclusion of expenses incurred outside test period).

1659. The Commission has determined that averaged expenses over a representative time period or amortized rate case expenses over a long period (in cases where the pattern of expenses is unusual or the filings infrequent) to be appropriate. The Carriers proposal, choosing to average over a four-year range with higher litigation expenses appears to be arbitrary absent compelling justification. The mere fact that the costs are higher in that four-year range is not compelling justification. Staff has proposed the use of the Carriers actual rate case litigation expenses from 2007 through 2009 and from 2008 through 2010, amortized over three years, rather than the use of out-of-period amounts proposed by the Carriers. Accordingly, the Carriers proposal is rejected.

iv. Anadarko's proposed adjustments to rates

1660. Anadarko adopts Staff's 2009 and 2010 costs of service, subject to certain adjustments.[865] The adjustments, with the exception of adjustment (e) (SR cost exclusion adjustments)[866] are uncontested. Adjustment (a) (post-retirement benefits other than pensions)[867] and adjustment (b) (income taxes on imputed management fees)[868] were

[865] Anadarko IB 282. Anadarko's proposed FERC rates for 2009 and 2010, as set forth in Appendix B, are based on the Staff's 2009 and 2010 costs of service and volumes subject to adjustments. Anadarko IB 281. The rate calculations for the 2010 rates in Appendix B are not final because the return for 2010 was held in abeyance pending the outcome of proceedings in Docket Nos. IS09-348, *et al.* Anadarko IB 281 n.1332.

[866] In Appendix B, Anadarko presents FERC rate calculations for each of Anadarko's remedy options 1 through 4 discussed in Section VIII.B of Anadarko's IB. Anadarko's fifth SR remedy option is based on the remedy proposed by the State. Given that the State could refine or modify that proposal in brief, Anadarko did not attempt to perform a rate calculation based on the State's remedy proposal.

[867] The Carriers agree that PBOPs and income taxes on imputed management fees should be properly reflected in rates and made the adjustments in their interstate rates, as Anadarko acknowledges (Anardarko IB 282 n.1335 and 283). Ex. ATC-8 at 46 (2009 FERC rates), Ex. ATC-8 at 58 (explaining that same adjustment from 2009 FERC rates is applied to 2010 FERC rates).

[868] Staff and Anadarko state that the Carriers adjusted their FERC rate filing to remove certain costs from Account 520, outside services, to reflect the amount incurred for federal and state income taxes on imputed management fees. Anadarko understands that this adjustment is pursuant to a settlement between the Carriers and the Internal

20140227-3052 FERC PDF (Unofficial) 02/27/2014

made by the Carriers in their FERC rate filings,[869] but appear not to have been picked up in the Staff's costs of service development. Adjustment (c) (charitable and lobbying expenses) was made by the Carriers for its RCA rates, and the Carriers now agree to make that adjustment for their FERC rates.[870] Adjustment (d) (depreciation/life of line) reflects the terms of an uncontested settlement filed by the parties to resolve those issues in this case.[871]

v. Other uncontested issues

1661. Anadarko's proposed adjustment to the Carriers' wages and salary expenses[872] is resolved by adoption of Staff's actual wage and salary expenses for the 2009 and 2010 test periods. Anadarko IB 286; RB 148.

1662. Anadarko no longer advocates an adjustment to the Carriers' treatment of operations control center costs,[873] without prejudice to reviewing and challenging any

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Revenue Service. Ex. ATC-8 at 46 (2009 FERC rates); Ex. ATC-8 at 58 (explaining that same adjustment from 2009 FERC rates is applied to 2010 FERC rates). Anadarko IB 283; Staff RB 107.

[869] Both the PBOP Earnings Credit and the adjustment for imputed management fees are applied to the Carriers' cost of service in Ex. ATC-16, Workpaper 7 (2009 FERC Rates); Ex. ATC-17 at Workpaper 7 (2010 FERC Rates).

[870] Anadarko states that the Carriers included charitable and lobbying expenses, in their FERC rates. Anadarko challenged the Carriers' inclusion of these costs in FERC rates. Accordingly, Anadarko's rate computations in Appendix B reflect the removal of charitable and lobbying expenses (along with other minor related expenses) from the Carriers' FERC rates. Anadarko IB 283-84; Staff RB 107-08. The Carriers do not take issue with the items related to charitable and lobbying expenses and have agreed to exclude such costs from their FERC rate filings. Carriers RB 182. This issue is thus uncontested. Anadarko IB 286; RB 150.

[871] A settlement certified on November 15, 2012, (141 FERC ¶ 63,012) and approved by the Commission on December 28, 2012 (141 FERC ¶ 61,263) resolved issues related to the life of the TAPS line and the factors to be used in calculating depreciation expense. As required by the settlement, Anadarko's FERC rate calculations for 2009 and 2010 contained in Appendix B reflect the life of line and depreciation factors used by the Carriers in their 2009 and 2010 rate filings.

[872] Ex. AT-42 at 21-22 (Brown).

[873] Ex. AT-42 at 22-23 (Brown).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

such costs in future Carrier rate filings. Staff agrees this is not being challenged. Staff RB 106; Anadarko IB 286; RB 148. Carriers RB 156 n.191.

1663. Anadarko's proposed adjustment to the Carriers' test period throughput levels for 2009 and 2010 FERC rates is resolved by adopting Staff's use of actual throughput for the 2009 and 2010 test periods (as adjusted for the oil spill). Anadarko IB 286.

1664. Anadarko no longer advocates an adjustment to the Carriers' method of allocating the Carriers' ad valorem tax expense (i.e., whether distance related), without prejudice to reviewing and challenging such allocation in future Carrier rate filings. Anadarko IB 286; RB 150; Carriers RB 156 n.191. This resolves the single issue Flint Hills raised in its briefs. Flint Hills IB 4-10, RB 1-4. Flint Hills, however, takes issue with Anadarko's statement that they no longer advocate this adjustment without prejudice to reviewing and challenging such allocation in future Carrier rate filings, because the issue was identified by the parties as one "that currently will need to be addressed during the Phase II hearing." "Joint Statement of Phase II Cost of Service Issues at 2, issue 3. (filed Aug. 31, 2012). Flint Hills contends that the Parties did address it at hearing and on brief, and thus an adequate record has been made to show sufficiently that Anadarko's adjustment was ill-conceived and lacks factual or legal support. Flint Hills RB 2. Since Anadarko withdrew its adjustment the issue is moot.

1665. According to the Carriers, Anadarko has withdrawn its prior arguments related to compensation expense in the 2009 interstate rates. Carriers RB 156 n.191 (citing Anadarko IB 285-87).

V. CONCLUSIONS

1666. This case shows an institutional mentality exemplified by the following language in a May 20, 1977 memo from F.K. Rickwood to D.A. Lucas from BP Pipelines Inc. concerning TAPS Owners Tariffs. "All the TAPS owners should want to file the highest possible tariff . . . ." Ex. AT-12 at 1, P 1. "As balanced shipper/owners, . . . should file a high tariff in order to minimize the combined government income from the field and the pipeline . . . ." *Id.* at 1, P 2 (a). It continues as follows:

> [A]ll the owners should file high for the following reasons: (i) At full throughput, a disparity of tariffs would cause all shippers to tender pro rata to the lowest tariff, with spillover to the next lowest, etc, with the end result that all shippers would pay the same average tariff. The owner with the highest tariff, however, would make the greatest profit. (ii) Alaska will endeavor to force the Interstate Commerce Commission to decrease the pipeline valuation and/or the owners' tariff, probably with some success. Accordingly, the higher the tariff filed initially probably the higher will be the tariff finally agreed with the ICC. (iii) Oil pipeline regulations are relatively favorable now, but this is expected to change for the worse in

20140227-3052 FERC PDF (Unofficial) 02/27/2014

> coming years. Therefore, the owners should want to maximize cash flows before the rules of the game are changed.

Id. at 2, P 2(c).

> The level of tariff which BP Pipelines considers it reasonably could defend is $7.25/bbl and this is the tariff we would file . . . This tariff gives an ICC return for the period July 1977 to December 1978 of 12.7%. Although this is higher than the 8% guideline set by the ICC, we consider we can justify this level, which is equivalent to a 13% return on capital employed, on the basis of (i) the current high cost of funds, and (ii) the high level of risk for BP Pipelines in its TAPS investment."

Id. at 5, P 7.

This was the mindset in 1977 and as this decision shows, continues to this day.

1667. The Carriers assert in their defense that the prudence inquiry is not about general business or management practices but about the reasonableness of the costs to be included in rates and whether the shippers are worse off as a result of the decision to incur the costs.[874] The Carriers are not entirely correct in their interpretation of *Violet*. *Violet* references industry practice and industry experts. How else would reasonableness be measured? *See Violet* at 283. Additionally, the shippers in this case contend that they have been harmed since the rates are higher than before SR with no concomitant improvement in service.

1668. As Staff asserts, imprudent costs included in rates shifts these costs to the citizens of Alaska and independent shippers. The Carriers imprudence impacts the rates interstate shippers pay and the budget of the State of Alaska. The TAPS revenues are a critical component of the State budget. Production tax and royalty revenues Alaska gets from ANS oil production are based on a "net-back" pricing mechanism. Royalty and taxes are calculated using a netback formula based upon the "wellhead" value of the oil. Part of the wellhead value calculation includes transportation costs, which are subtracted from the market value of the oil where it is sold, principally at ports on the West Coast. The higher the transportation costs, the lower the wellhead value. This in turn, reduces the royalties and taxes owed to the state. *See Trans Alaska Pipeline Rate Cases*, 436 U.S. 631, 635 n.6 (1978). The TAPS tariff rate is an important component of the calculation, and the higher the TAPS rate the lower the revenues Alaska receives. Staff RB 5.

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[874] Carriers IB 3 (citing *Violet v. FERC,* 800 F.2d 280, 283 (1st Cir. 1986)).

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1669. The evidence in this case shows that the Carriers were imprudent in the sanction and execution of the SR project. [875] Even taking into account any latitude and discretion the Carriers are entitled as business managers, their actions with respect to the sanction and execution of the SR project are found to be imprudent. The Carriers have not overcome serious doubt, much less affirmatively demonstrated the prudence of the challenged expenses.[876] Consequently, based on the preponderance of the evidence it is concluded that the Carriers were imprudent in the sanction and execution of the SR project. [877] The SR project was a discretionary project. However, the Carriers failed to adequately review the condition of the existing pumps and drivers. They failed to take into account that the legacy equipment was efficient and reliable and had adequate spare parts. The Carriers ignored the in depth studies performed by Alyeska regarding potential upgrades to the legacy pumps and controls systems. They ignored warnings of competent, subject matter expert employees. The Carriers unreasonably dismissed studies indicating that an alternative to their chosen course of action was more cost effective (e.g., retaining and upgrading the legacy equipment).

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[875] The pipeline was placed into operation in 1977 by the time this project was sanctioned the asset was almost totally depreciated. That is one of the reasons the project at one point was a "Reinvestment Strategy." However, the pipeline was operating efficiently at 99 percent reliability and the equipment (except for automation) was not obsolete. TAPS is a critical to our national energy infrastructure. This pipeline provides 10 percent of our nation's domestic oil production. Studies indicate that very substantial additional recoverable oil reserves exist both in the ANS region and in the adjacent off-shore area. The economic development and production of these valuable national energy resources will depend upon TAPS and its rates. Staff RB 6.

[876] As a regulated monopoly, the service provider has a legal obligation to provide service at competitive rates, comparable to those found in a competitive market. Here, the Carriers acted in a way grossly in conflict with their duties as a regulated monopoly. No business in a competitive market would so cavalierly spend their own money as the Carriers have done in this case.

[877] The pipeline was placed into operation in 1977 by the time this project was sanctioned the asset was almost totally depreciated. That is one of the reasons the project at one point was a "Reinvestment Strategy." However, the pipeline was operating efficiently at 99 percent reliability and the equipment (except for automation) was not obsolete. TAPS is a critical to our national energy infrastructure. This pipeline provides 10 percent of our nation's domestic oil production. Studies indicate that very substantial additional recoverable oil reserves exist both in the ANS region and in the adjacent off-shore area. The economic development and production of these valuable national energy resources will depend upon TAPS and its rates. Staff RB 6.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

1670. Additionally, the Carriers failed to conduct adequate engineering studies prior to sanction. The Carriers did not perform sufficient front end loading. Further, they commenced construction prior to completing sufficient engineering. They failed to determine power supply for the new pumps. In addition, they sanctioned the SR project before knowing its scope. The Carriers did not determine if existing equipment could be upgraded to obtain the same benefits as electrification. The Carriers did not have an adequate understanding of the project costs before sanction. They also did not have an adequate understanding of the project benefits before sanction. They impermissibly considered benefits to affiliated producers. In addition, they failed to justify the SR project with adequate economic support. Moreover, the Carriers' attempt to justify the sanction of the SR project after the fact are unpersuasive and indicate a lack of thoroughness in their initial studies. Electrification was not necessary to secure cost savings or to address low flow issues. The Carriers failed to properly determine regulatory requirements.

1671. Further, in the SR project execution the Carriers failed to develop a realistic schedule. They failed to reasonably assess the risks and feasibility of the schedule. Further, they failed to hire a management team with relevant experience. They failed to adequately supervise contractors. In addition, they failed to implement a management of change program. The sense is that execution was accomplished in a trial and error manner.

1672. The Commission is free, within the framework of its statutory authority, to make such pragmatic adjustments to reconcile equitably diverse interests whenever called for by particular circumstances. *Mobil Oil Corp. v. F.P.C.*, 417 U.S. 283, 331 (1974); *F.P.C. v. Natural Gas Pipeline Co.*, 315 U. S. 575, 586 (1942).

1673. As a result, remedy 3 proposed by Anadarko seems fair and results in rates which are just and reasonable. Thus, the Carriers are allowed to flow through rates the costs associated with SR AFE S020 and Supplement 1. This total is $229.2 million to be amortized over the remaining life of the pipeline. For the 2009 and 2010 filed rates the rate base exclusion is $225.2 million. The costs for Supplement 2 and forward are deemed costs which a reasonable utility management would not have made in good faith, under the same circumstances and at this point in time.

1674. As found above, the project is not used and useful and does not provide any discernable benefits to shippers through personnel reductions, reduced major maintenance, enhanced reliability, additional throughput capability, or any other criteria. The project does not provide an enhanced level of service to ratepayers. Thus, used and useful is an independent and separate ground for disallowance of the rates. Anadarko's fourth disallowance theory under use and useful would be equitable. It would be reasonable to disallow all electrification costs under the use and useful standard. However, this is an alternative remedy were the project considered prudent (which is not the decision reached in this case). The fourth remedy proposes to exclude from rate base

20140227-3052 FERC PDF (Unofficial) 02/27/2014

all capital costs for the portion of SR related to electrification of the pump stations. The total capital costs to be excluded from rate base for 2009 and 2010 would be $397.1 million.[878] Again Anadarko argues that this remedy would apply to future rates and would eliminate future prudence litigation. The allowed costs would be amortized over the entire life of TAPS. For 2009 and 2010 rates the allowed amount would be $57.3 million. Calculated as follows: $454.4 capital costs in filed rates minus $397.1 million equals $57.3 million in allowed 2009 and 2010 rates.[879] For 2009 the impact of the reduction would be a cost of service reduction of $66 million and for 2010 of $51.3 million. Staff recommends that the $8.4 million cost of the SCADA system upgrade be excluded from rate base under used and useful since the upgrades to the SCADA have led to constant alarm flooding at the OCC exponentially in excess of Alyeska's own goals, rendering TAPS system controllers significantly less able to respond to emergency events on the system, making the system significantly less reliable. Staff is correct and these costs should not be allowed in rates.

1675. For the cost of service issues, it is concluded that it is appropriate to use actual cost data for the entire period in this case. In addition, the oil spill expense is appropriately excluded as a nonrecurring event, thus, Staff's upward volume adjustment is appropriate. Further, the supplemental ad valorem tax paid in 2010 for the 2006 tax year cannot be flowed through the 2010 rates. Finally, actual litigation expenses for the years 2007-2009 and 2008-2010 for 2009 and 2010 rate cases will be amortized over a three-year period.

1676. The entire record has been thoroughly reviewed and considered. Any matters not discussed in this initial decision, have been determined to be irrelevant, immaterial or meritless. Arguments made on brief that were unsupported by record evidence or legal precedent have been accorded no weight.

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[878] In his testimony Grasso also proposed a reduction to TAPS operating costs associated with electrification. Ex. AT-225 at 4, 5. However, Anadarko is limiting its remedy to capital costs to simplify the issues for decision and facilitate the implementation of the remedy. Anadarko argues that if any of the decisional bodies were to adopt credits to operating costs for purported SR savings (which would not be justified) they should also disallow any operating costs shown as imprudent as quantified by Grasso and the State witnesses.

[879] The $397.1 million excluded are "actual" capital costs (not estimates). Ex. AT-225 at 4 (Illustration No. 1); AT-261; Tr. 4258:9-4259:5; 4272:13. Quantification of electrification spend was developed by Carrier witness Toof, Ex. AT-228. Electrification capital costs used by Grasso in Ex. AT-225 at 4 (Illustration No. 1) are the amounts placed in rate base shown on Ex. AT-228 at 9, line 5. The costs for 2007-2009 are actual costs. *See* Ex. AT-228 at 9, n.1 and Ex. SOA-582.

20140227-3052 FERC PDF (Unofficial) 02/27/2014

VI. ORDER

1677. IT IS ORDERED, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that:

1678. Within thirty days from the issuance of the final order of the Commission in this proceeding, the Carriers must make a compliance filing establishing rates in conformance with this initial decision.

1679. Within thirty days from the issuance of the final order of the Commission in this proceeding, the Carriers must file a refund report and refund shippers in accordance with this initial decision.

Carmen Ana Cintron

Presiding Administrative Law Judge

20140227-3052 FERC PDF (Unofficial) 02/27/2014

Document Content(s)

TAPS ID Public Final Read Only.DOCX.....1-542