

**6/7/07 TAPS
TARRIFF
PROCEED-
INGS, & OIL
PIPELINE
INTEGRITY &
CORROSION
(FILE 1)**



**House Resources Committee
Alaska State Legislature
Representative Carl Gatto, Co-Chairman**

May 25, 2007

To: (H) Resources Members

RE: Hearings

Anchorage LIO

Thursday, June 7th 9:00am-5:00pm

- TAPS tariff proceedings before the FERC
 - Oil pipeline integrity and corrosion
- Both meetings will be teleconferenced

Based on comments from members I have decided to hold hearings on these issues Thursday, June 7th to ensure maximum participation. Hearing materials will be available shortly.

Thank you.

CG/cr

Alaska State Capitol, Room 124 • Juneau, Alaska 99801
Committee Aide - Cody Rice
(907) 269-0220 phone • (907) 269-0221 fax

BP EXPLORATION (ALASKA) INC.



FACSIMILE TRANSMITTAL SHEET

TO: Honorable Craig Johnson FROM: Tonia Bonock / PJ

COMPANY: Alaska Legislative DATE: 8/2/07 11:00 AM - 11:40 11:50

FAX NUMBER: (907) 465-3072 218204 TOTAL NO. OF PAGES INCLUDING COVER: 11

PHONE NUMBER: (907) 465-4993 SENDER'S REFERENCE NUMBER: N/A

RE: Responses to 8/1/07 Resource Committee Meeting

URGENT FOR REVIEW PLEASE COMMENT PLEASE REPLY PLEASE RECYCLE

NOTES/COMMENTS:

bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

August 2, 2007

BY FACSIMILE (without attachments) and OVERNIGHT DELIVERY

Hon. Carl Gatto
Hon. Craig Johnson
Co-Chairs, House Resources Committee
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

Re: Responses to Requests from June 7, 2007 Meeting of House Resources Committee

Dear Representatives Gatto and Johnson:

BP Exploration (Alaska) Inc. ("BPXA") appreciates the opportunity to respond to several requests from the June 7, 2007 meeting of the House Resources Committee. Please find below the answers to each of the Members' requests, which we have reproduced for your convenience.

Requests from Rep. Seaton

• Requests from September 2006 Memoranda

Rep. Paul Seaton posed four questions to BPXA in two memoranda, dated September 7, 2006 and September 14, 2006.^{1/}

1. **I requested from BP verification of information [that] has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested any BP correspondence with TAPS on the issue.**

Since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in

^{1/} As Rep. Dahlstrom explained at the June 7 meeting, these requests were not originally addressed to BPXA in September 2006. BPXA was provided a copy of the requests shortly before the June 7 meeting.

TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined (in the memorandum)? [Question from September 7, 2006 memorandum, "Transit Lines and TAPS Pigging Schedules"]

As I explained in my testimony at the June 7 meeting, the frequency of pigging^{2/} on the oil transit lines ("OTLs") in the Prudhoe Bay Unit ("PBU") and on the Trans-Alaska Pipeline System ("TAPS") may differ due to a number of factors, including operational requirements and for corrosion management reasons. As I described at the June 2007 meeting, BPXA runs maintenance pigs frequently on North Slope production lines and employs full-time crews dedicated to those pigging operations.

The sales-quality crude oil in the PBU OTLs is not "the same market oil" flowing through the TAPS. Indeed, the primary reason that the Alyeska Pipeline Service Company ("Alyeska"), which operates the TAPS, runs maintenance pigs at the frequency Rep. Seaton notes is that the TAPS market oil is a combination of crude oil from a wide number of different North Slope fields and operators. Some of these oils are prone to develop paraffin that can form on the interior of the pipeline. Over the approximately 800-mile length of the TAPS, this paraffin can, when the temperature drops, reduce the efficiency of the pipeline hydraulics system. Maintenance pig runs are thus required at more frequent intervals to combat the paraffin build-up. BPXA's approach to maintenance pig runs is consistent with Alyeska's flow regime strategy for lines on which, for example, paraffin build-up or temperature present issues. In comparison to the TAPS however, the PBU OTLs, which are only eight miles long on either side of Pump Station 1, carry crude oil that is relatively sweet, runs at higher temperatures, and does not contain high levels of paraffin.

As I further testified at the June 7 meeting, in-line inspections are typically undertaken to provide information as to the integrity of a line. BPXA has historically monitored the 16-mile section of the PBU OTL system via several inspection techniques, including in-line inspection and external ultrasonic inspection. It is an industry-accepted practice to use ultrasonic inspection techniques where the lines are readily accessible above ground and are relatively short in length. The TAPS system is, as noted, approximately 800 miles long, and approximately 50% of the line is buried below ground level. Those circumstances make in-line inspection the only practical means of inspection.

Regarding Rep. Seaton's statements about Pump Station #1, BPXA respectfully submits several points of clarification. First, cleaning pig runs were "done previously," *i.e.*, prior to the runs in 2006 to which Rep. Seaton appears to refer, on the PBU OTLs. Second, based on experience from those prior cleaning pig runs in the Eastern Operating Area ("EOA") in the early 1990s in which some scale flakes or chips collected in the screens^{2/} of Pump Station #1,

^{2/} "Pigging" encompasses three different types of activities: runs by cleaning pigs, runs by maintenance pigs (which are a type of cleaning pig that are used both to ensure that lines are clean and for other operational reasons), and in-line inspection (colloquially known as "smart pigging").

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there was some discussion between BPXA and Alyeska in 2006 about the potential presence of solids^{4/} in future pigging runs.^{5/} Third, it is not the case that "other arrangements were not made" to address this potential issue. To the contrary and among other things, modifications were made to Tank 110 in 2006 to allow it to handle any solids that were returned as a result of pigging runs, and a series of runs were completed in 2006.^{6/} Finally, subsequent pigging runs did not result in a particularly high "volume of sludge." Indeed, Alyeska assessed the pigging returns sent to Tank 110 during those 2006 pigging activities and reported a total of only 32 barrels of sediment and 292 barrels of water recovered for all the EOA (Flow Station ("FS") 2-to-Skid 50) and Western Operating Area ("WOA") (Gathering Center ("GC") 1-to-Skid 50) OTLs.^{7/} These totals are well within the base, sediment & water ("BS&W") specifications for the amount of oil that has been shipped through those lines.

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This request appears to assume a condition that did not exist. As described in response to Question 1, Alyeska assessed pigging returns from the 2006 pigging activities on the EOA and WOA OTLs and reported minimal returns of sediment and water. Similarly, when BPXA maintenance-pigged the Lisburne Production Center ("LPC") OTL (another North Slope OTL not part of the PBU) in 2006, the runs returned minimal solids (less than 5 gallons) and revealed minimal damage.

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Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

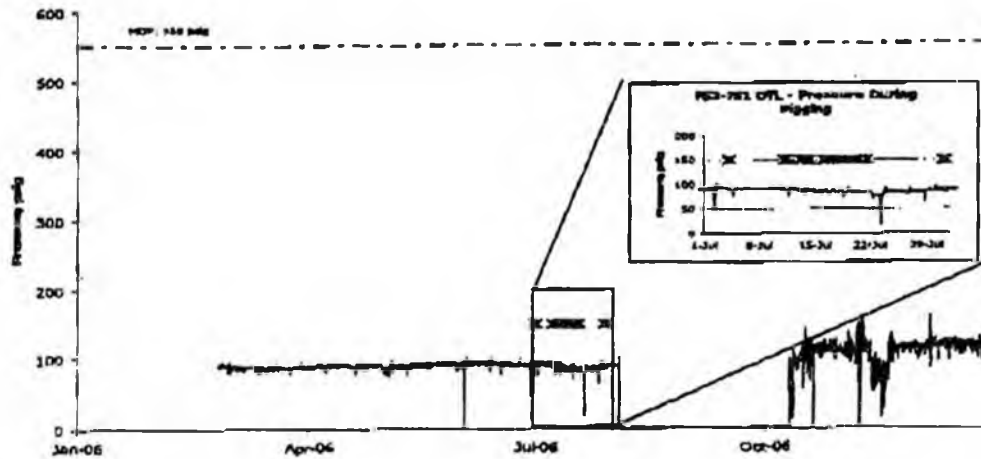


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

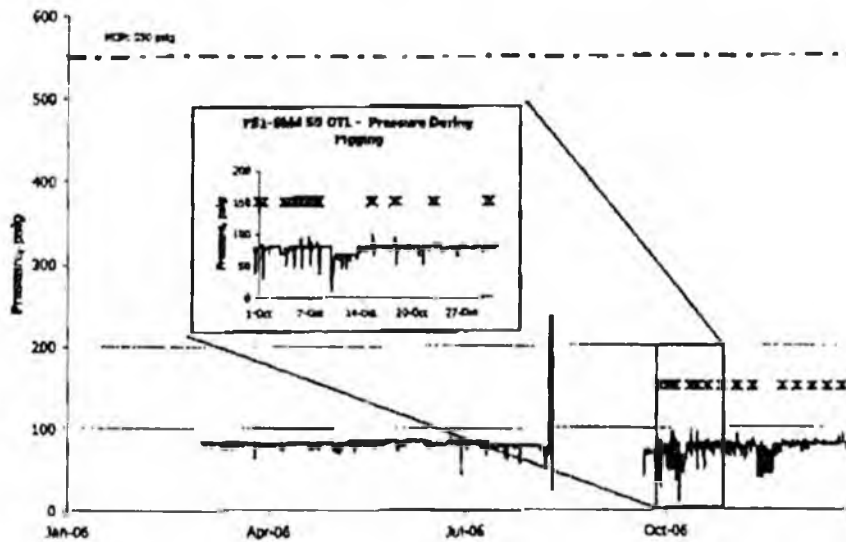


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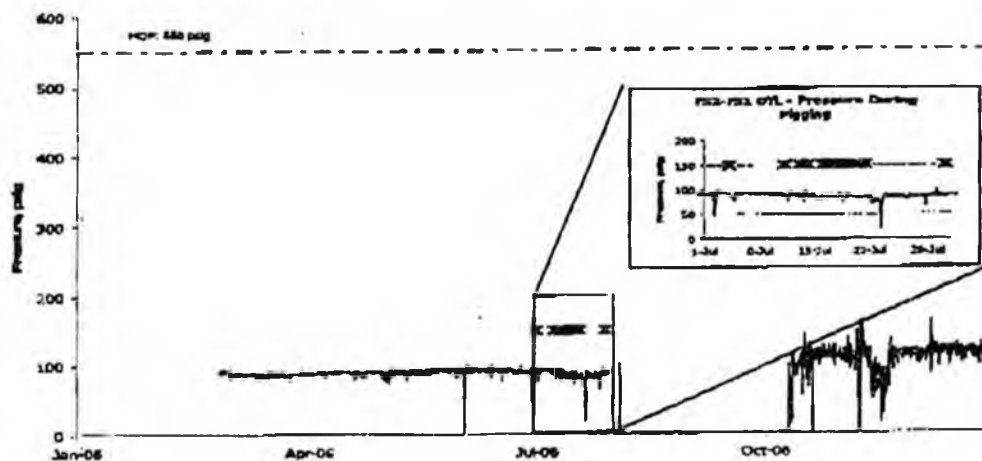


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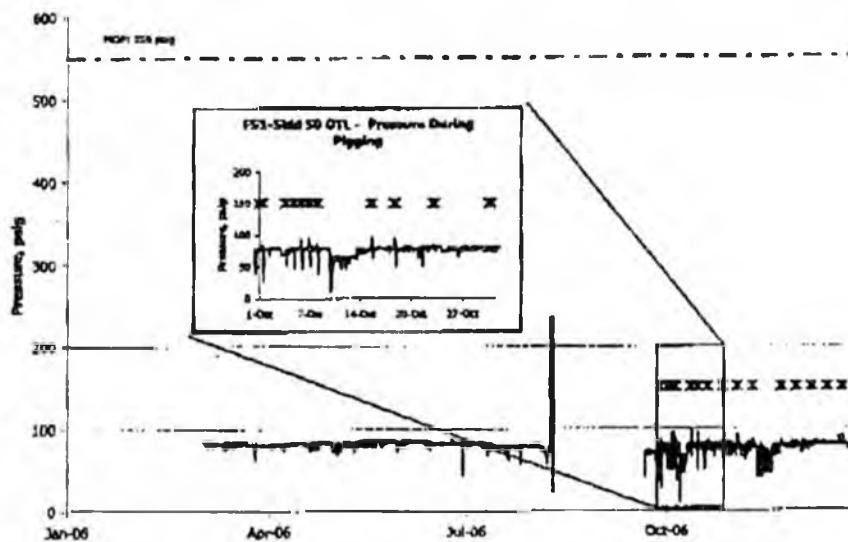
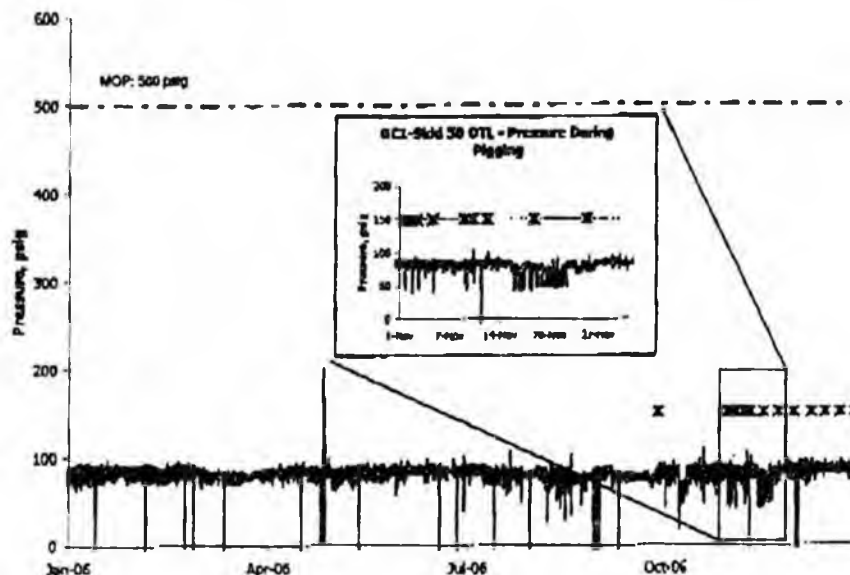


Figure 4. WOA: GCI-to-Skid 50 OTL, 5-minute average pressure data overlaid with pigging events.



3. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination. [Request from September 14, 2006 memorandum]

As Rep. Seaton notes, each field has different characteristics, including the type and quality of crude produced; the weather conditions and terrain in which the field is located; the level of pressure needed to move crude through pipelines; and whether the pipelines must be buried below ground or travel through water. The pipelines themselves are in turn specific to the field; among other things, pipelines differ in terms of metallurgy and size. These differences, in both fields and pipelines, are all part of the calculus that informs decisions about the maintenance procedures used on any given pipeline, including decisions whether and when to run cleaning and/or maintenance pigs and/or to conduct in-line inspections. As noted above in response to Question 1, BPXA's cleaning and maintenance pig data on the PBU OTLs show that there has been very little sediment build-up in them over time.

BPXA has previously explained that there are two different types of pipelines in the PBU that carry crude oil: OTLs, which carry sales quality oil downstream of processing facilities, and flow lines (sometimes also known as "production gathering lines"), which carry multi-phase flow from well heads to processing facilities. The leaks in 2006 occurred in the EOA and WOA OTLs, which are large-diameter, low-stress, above-ground lines. BPXA operates no other large-diameter, low-stress, above-ground OTLs and is not aware of any such lines being operated by any affiliate. Meaningful comparison to other lines of different sizes that are used in different service, under different conditions, and to transport oil of different quality and/or composition is thus not possible.

BPXA understands Rep. Seaton's statement regarding standard industry practice to refer to maintenance pigging. As BPXA has previously explained, it is not aware of any industry standard or recommended industry practice with respect to cleaning or maintenance pigging.

4. **Was the fact that the Prudhoe Bay transit lines were carrying much less than design volumes combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines? [Question from September 14, 2006 memorandum]**

BPXA has not identified any correlation between operational efficiency of the OTLs and the potential for reduced cross-sectional area, and that potential was not a consideration in the maintenance strategy of the OTLs. BPXA has also not observed any appreciable change in the operating pressure of the system due to the accumulation of solids.

The flow in the OTLs has naturally lost velocity over time as a result of the declining production of the field, and any change in cross-sectional area of the OTLs would likely have been masked by this natural decline in output. In any event, prior to the leaks BPXA saw no indications of restrictions in the line that might have led to reduced throughput.

BPXA's post-leak analysis bears out these observations. Even though BPXA understands, in retrospect, that the reduction in volume of oil may have contributed to the circumstances that led to the leaks in the OTLs in 2006, the reduction in the cross-sectional area of the lines due to build-up of solids was relatively minor during the 10-year period prior to the 2006 leaks. As discussed above in response to Question 1, cleaning and maintenance pigging of the OTLs in 2006 revealed very little sediment build-up over time.

- Oral questions from June 7 meeting

Rep. Seaton posed the following questions at the hearing on June 7:

5. **What percentage of the lines that BP is operating in the Prudhoe Bay Unit will the 18 smart pig runs in 2007 encompass?**

Of the 18 in-line inspections that BPXA has planned for 2007, 16 are being performed on PBU pipelines; the others are being performed on a Badami pipeline and a Milne Point Unit pipeline. These 16 PBU pipelines account for 10% (16 of 164) of all PBU pipelines transporting crude oil (both flowlines and OTLs).^{10/}

6. **Has BP billed Conoco or Exxon for the repairs and the maintenance that arose from the shutdown, the bypass line and those repairs yet? If they have been billed, [has] that been turned down? If they haven't been billed, when [is BP] planning on billing for that?**

BPXA's working interest owner partners, ExxonMobil and ConocoPhillips, have approved the funds and are making payments for the spill response, subsequent inspections, and bypass construction. BPXA has submitted an Authorization for Expenditure request for the OTL replacement to ExxonMobil and ConocoPhillips, and that request is under review. Neither ExxonMobil nor ConocoPhillips has refused to pay any bills sent to them regarding any of these activities.

Question from Rep. Johnson at June 7 meeting

7. **Will the costs of replacement of the affected lines be treated as a tax deduction under [the Petroleum Production Tax] by BP?**

BPXA has previously provided a written response to this question. On February 15, 2007, Doug Suttles, President of BPXA, submitted a letter on this subject to the Honorable Members of the Alaska State Legislature. A copy of that letter is attached hereto as Exhibit 4. This correspondence bears the Bates labels BPXA-AKLEGIS000044-45.

^{10/} The total number of pipelines does not include facility piping or well lines, which, due to the nature of their construction (i.e., they are of smaller diameter and shorter lengths and include sharp bends), cannot readily be in-line inspected using current technology.

Question from Rep. Fairclough, who attended the June 7 meeting of the Committee, joined by Rep. Seaton

8. Are the deconstructions of the affected OTLs being charged against the dismantlement, removal, & restoration ("DR&R") fund? If so, will that charge decrease the fund? How would such a charge affect the FERC and rate calculations in the future? Would such a charge result in the DR&R fund being hit twice, for removal of a portion of the line and for the expense of creating a new line?

When oil and gas assets are constructed, an estimate of the costs for DR&R of those assets is established as a future obligation (or "liability") by the corporation owning the assets and recorded as a provision on its balance sheet. The DR&R provision is an accounting entry and does not represent the establishment of a specific "fund" or escrow account. When the assets (or a portion of the assets) are removed, the actual costs incurred in the related DR&R activity are charged against this provision such that the total DR&R provision for the assets (or portion of the assets) will decrease. When a new pipeline is installed, the DR&R provision is increased to reflect the new obligation associated with the new pipeline. Thus, in the case of the replacement of the PBU OTLs, the provision will be reduced with respect to the old pipeline and increased with respect to the new pipeline. This accounting treatment is in accordance both with U.S. Generally Accepted Accounting Principles and BPXA's internal accounting policy.

With regard to Rep. Fairclough's question about the Federal Energy Regulatory Commission ("FERC") and future rate calculations, the PBU OTLs are not common carrier pipelines and thus are not subject to FERC tariffs. The costs to remove and/or replace these OTLs will therefore not impact tariff rates.

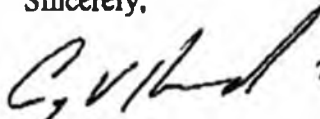
* * *

These responses contain highly sensitive, private business information and documents. Accordingly, BPXA believes that the State is required to treat and maintain this letter and these documents as confidential under the commercial privacy protection afforded by Article I, Section 22 of the Alaska Constitution; AS 40.25.120(a)(4); and AS 40.25.120(b)(6). BPXA respectfully requests that the confidentiality of this letter and these documents be preserved and that, if you wish to consider whether any of this information or these documents should be made public, BPXA be provided 60 days notice prior to any such disclosure to any third party, including other governmental entities.

Hon. Carl Gallo
Hon. Craig Johnson
August 2, 2007
Page 10

Please feel free to call me if I may be of further assistance.

Sincerely,

 FOR
TONY BROCK

Tony Brock, Technical Director
BP Exploration (Alaska), Inc.

Attachments: as stated

cc: Hon. Charlie Huggins, Chair, Senate Resources Committee
Hon. Paul Seaton
Hon. Anna Fairclough (by overnight delivery only, without exhibits)

ALASKA STATE HOUSE OF REPRESENTATIVES



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Homer AK 99603
(907)-235-2921
Fax# (907)-235-4008

Session:
(907)-465-2689
FAX# (907) 465-3472
State Capital
Room 102

REPRESENTATIVE PAUL SEATON DISTRICT 35

Memorandum

From: Rep. Paul Seaton
To: House Resources Co-Chair Rep. Ralph Samuels
House Resources Co-Chair Rep. Jay Ramras
Senate Resources Chair Sen. Tom Wagoner
Date: September 7, 2006
Re: Transit Lines and TAPS Pigging Schedules

BP testified to the Joint House and Senate Resources Committee meeting on August 18th that they did not think they needed to pig clean and smart pig the transit lines because they were handling market ready oil - that is oil with the majority of the water and contaminants removed. However, other information has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested from BP verification of that information and any BP correspondence with TAPS on the issue at the last meeting and am awaiting a response.

Additional information available from Alyeska Stakeholders Information Office published August 2006 entitled "Pigging the Trans Alaska Pipeline System" says that "cleaning pigs run weekly or every other week, smart pigs are scheduled every three years...." and "...in 29 years of operation, 60 smart pigs have been run to inspect the pipeline."

Please submit the following question for an answer at the next Resources meeting: since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined above?

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Memorandum

From: Rep. Paul Seaton
To: House Resources Co-Chair Rep. Ralph Samuels
House Resources Co-Chair Rep. Jay Ramras
Senate Resources Chair Sen. Tom Wagoner
Date: September 14, 2006
Re: BP Transit lines pigging information request

Please submit the following requests for information to BP for so we can have a discussion of the matter at the next Resources meeting:

1. We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks.

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3. Was the fact that the Prudhoe Bay transit lines were carrying much less than design volume combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines?

BP EXPLORATION (ALASKA) INC.



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 COMPANY: AK legislature DATE: 8/2/07 11:00 AM - 11:40 11:50
 FAX NUMBER: (907) 465-3872 269504 TOTAL NO. OF PAGES INCLUDING COVER: (11)
 PHONE NUMBER: (907) 465-4993 SENDER'S REFERENCE NUMBER: N/A
 RE: Responses to 8/1/07 YOUR REFERENCE NUMBER:
Resource Committee Meeting

URGENT FOR REVIEW PLEASE COMMENT PLEASE REPLY PLEASE RECYCLE

NOTES/COMMENTS:

bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
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August 2, 2007

BY FACSIMILE (without attachments) and OVERNIGHT DELIVERY

Hon. Carl Gatto
Hon. Craig Johnson
Co-Chairs, House Resources Committee
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

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Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

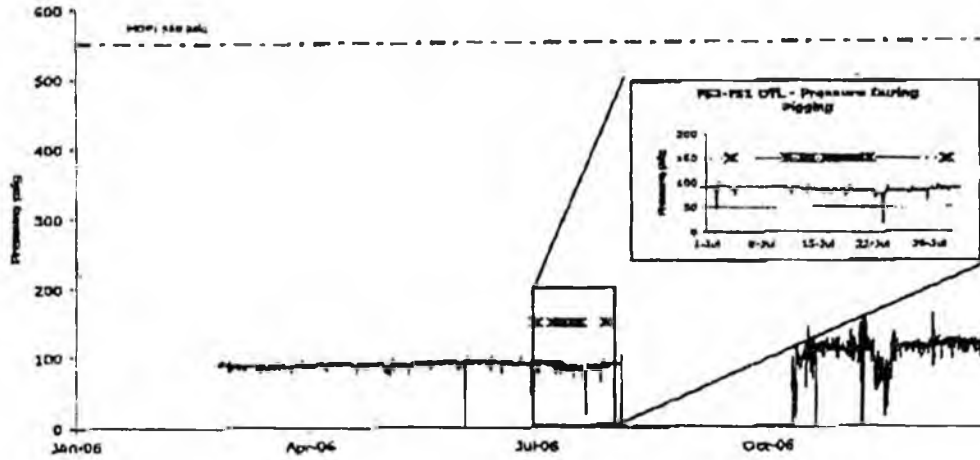


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.

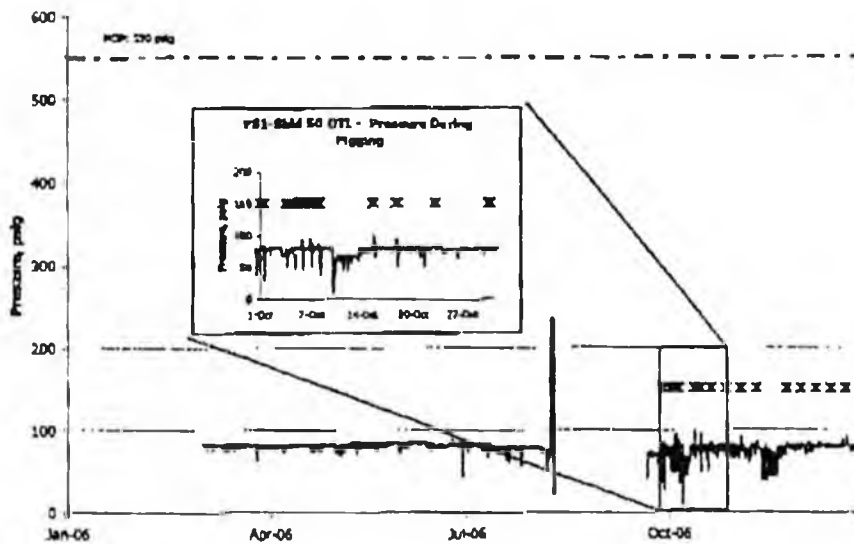


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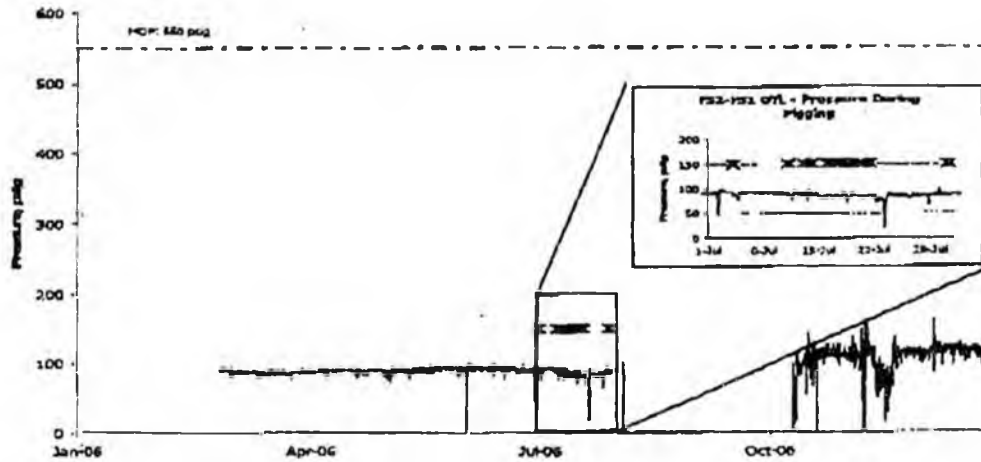
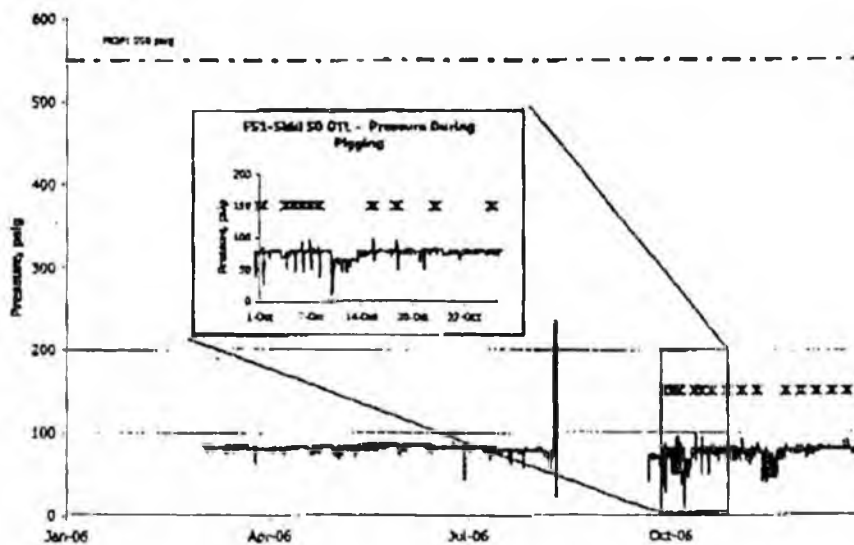
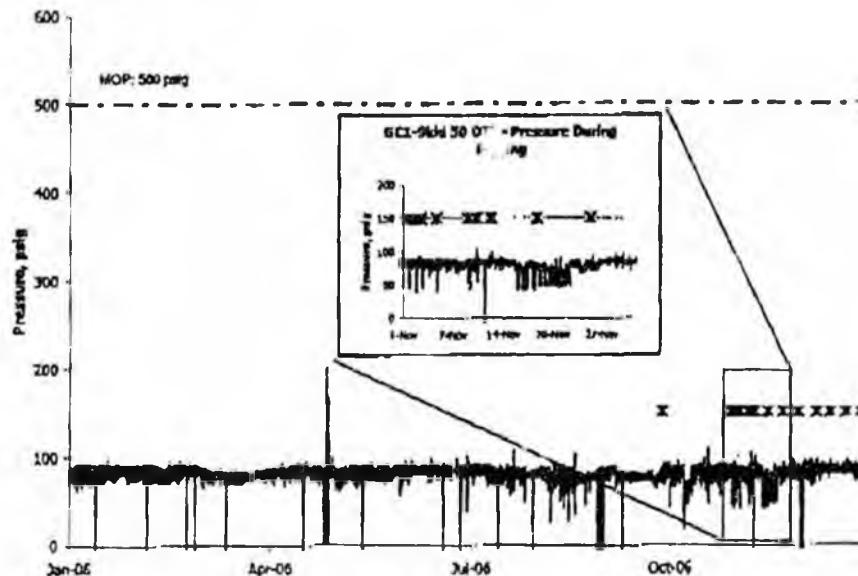


Figure 3. EOA: FS1-to-Skid 50 OTL, hourly average pressure data overlaid with pigging events.



Dup?

Figure 4. WOA: GCI-to-Skid 59 OTL, 5-minute average pressure data overlaid with pigging events.



3. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination. [Request from September 14, 2006 memorandum]

As Rep. Seaton notes, each field has different characteristics, including the type and quality of crude produced; the weather conditions and terrain in which the field is located; the level of pressure needed to move crude through pipelines; and whether the pipelines must be buried below ground or travel through water. The pipelines themselves are in turn specific to the field; among other things, pipelines differ in terms of metallurgy and size. These differences, in both fields and pipelines, are all part of the calculus that informs decisions about the maintenance procedures used on any given pipeline, including decisions whether and when to run cleaning and/or maintenance pigs and/or to conduct in-line inspections. As noted above in response to Question 1, BPXA's cleaning and maintenance pig data on the PBU OTLs show that there has been very little sediment build-up in them over time.

BPXA has previously explained that there are two different types of pipelines in the PBU that carry crude oil: OTLs, which carry sales quality oil downstream of processing facilities, and flow lines (sometimes also known as "production gathering lines"), which carry multi-phase flow from well heads to processing facilities. The leaks in 2006 occurred in the EOA and WOA OTLs, which are large-diameter, low-stress, above-ground lines. BPXA operates no other large-diameter, low-stress, above-ground OTLs and is not aware of any such lines being operated by any affiliate. Meaningful comparison to other lines of different sizes that are used in different service, under different conditions, and to transport oil of different quality and/or composition is thus not possible.

BPXA understands Rep. Seaton's statement regarding standard industry practice to refer to maintenance pigging. As BPXA has previously explained, it is not aware of any industry standard or recommended industry practice with respect to cleaning or maintenance pigging.

4. **Was the fact that the Prudhoe Bay transit lines were carrying much less than design volumes combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines?** [Question from September 14, 2006 memorandum]

BPXA has not identified any correlation between operational efficiency of the OTLs and the potential for reduced cross-sectional area, and that potential was not a consideration in the maintenance strategy of the OTLs. BPXA has also not observed any appreciable change in the operating pressure of the system due to the accumulation of solids.

The flow in the OTLs has naturally lost velocity over time as a result of the declining production of the field, and any change in cross-sectional area of the OTLs would likely have been masked by this natural decline in output. In any event, prior to the leaks BPXA saw no indications of restrictions in the line that might have led to reduced throughput.

BPXA's post-leak analysis bears out these observations. Even though BPXA understands, in retrospect, that the reduction in volume of oil may have contributed to the circumstances that led to the leaks in the OTLs in 2006, the reduction in the cross-sectional area of the lines due to build-up of solids was relatively minor during the 10-year period prior to the 2006 leaks. As discussed above in response to Question 1, cleaning and maintenance pigging of the OTLs in 2006 revealed very little sediment build-up over time.

- Oral questions from June 7 meeting

Rep. Seaton posed the following questions at the hearing on June 7:

5. **What percentage of the lines that BP is operating in the Prudhoe Bay Unit will the 18 smart pig runs in 2007 encompass?**

Of the 18 in-line inspections that BPXA has planned for 2007, 16 are being performed on PBU pipelines; the others are being performed on a Badami pipeline and a Milne Point Unit pipeline. These 16 PBU pipelines account for 10% (16 of 164) of all PBU pipelines transporting crude oil (both flowlines and OTLs).^{10/}

6. **Has BP billed Conoco or Exxon for the repairs and the maintenance that arose from the shutdown, the bypass line and those repairs yet? If they have been billed, [has] that been turned down? If they haven't been billed, when [is BP] planning on billing for that?**

BPXA's working interest owner partners, ExxonMobil and ConocoPhillips, have approved the funds and are making payments for the spill response, subsequent inspections, and bypass construction. BPXA has submitted an Authorization for Expenditure request for the OTL replacement to ExxonMobil and ConocoPhillips, and that request is under review. Neither ExxonMobil nor ConocoPhillips has refused to pay any bills sent to them regarding any of these activities.

Question from Rep. Johnson at June 7 meeting

7. **Will the costs of replacement of the affected lines be treated as a tax deduction under [the Petroleum Production Tax] by BP?**

BPXA has previously provided a written response to this question. On February 15, 2007, Doug Suttles, President of BPXA, submitted a letter on this subject to the Honorable Members of the Alaska State Legislature. A copy of that letter is attached hereto as Exhibit 4. This correspondence bears the Bates labels BPXA-AKLEGIS000044-45.

^{10/} The total number of pipelines does not include facility piping or well lines, which, due to the nature of their construction (i.e., they are of smaller diameter and shorter lengths and include sharp bends), cannot readily be in-line inspected using current technology.

Question from Rep. Fairclough, who attended the June 7 meeting of the Committee, joined by Rep. Scaton

8. **Are the deconstructions of the affected OTLs being charged against the dismantlement, removal, & restoration ("DR&R") fund? If so, will that charge decrease the fund? How would such a charge affect the FERC and rate calculations in the future? Would such a charge result in the DR&R fund being hit twice, for removal of a portion of the line and for the expense of creating a new line?**

When oil and gas assets are constructed, an estimate of the costs for DR&R of those assets is established as a future obligation (or "liability") by the corporation owning the assets and recorded as a provision on its balance sheet. The DR&R provision is an accounting entry and does not represent the establishment of a specific "fund" or escrow account. When the assets (or a portion of the assets) are removed, the actual costs incurred in the related DR&R activity are charged against this provision such that the total DR&R provision for the assets (or portion of the assets) will decrease. When a new pipeline is installed, the DR&R provision is increased to reflect the new obligation associated with the new pipeline. Thus, in the case of the replacement of the PBU OTLs, the provision will be reduced with respect to the old pipeline and increased with respect to the new pipeline. This accounting treatment is in accordance both with U.S. Generally Accepted Accounting Principles and BPXA's internal accounting policy.

With regard to Rep. Fairclough's question about the Federal Energy Regulatory Commission ("FERC") and future rate calculations, the PBU OTLs are not common carrier pipelines and thus are not subject to FERC tariffs. The costs to remove and/or replace these OTLs will therefore not impact tariff rates.

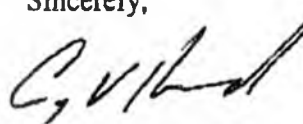
* * *

These responses contain highly sensitive, private business information and documents. Accordingly, BPXA believes that the State is required to treat and maintain this letter and these documents as confidential under the commercial privacy protection afforded by Article I, Section 22 of the Alaska Constitution; AS 40.25.120(a)(4); and AS 40.25.120(L)(6). BPXA respectfully requests that the confidentiality of this letter and these documents be preserved and that, if you wish to consider whether any of this information or these documents should be made public, BPXA be provided 60 days notice prior to any such disclosure to any third party, including other governmental entities.

Hon. Carl Gatto
Hon. Craig Johnson
August 2, 2007
Page 10

Please feel free to call me if I may be of further assistance.

Sincerely,

 FOR
TONY BROCK

Tony Brock, Technical Director
BP Exploration (Alaska), Inc.

Attachments: as stated

cc: Hon. Charlie Huggins, Chair, Senate Resources Committee
Hon. Paul Seaton
Hon. Anna Fairclough (by overnight delivery only, without exhibits)

Alaska State Legislature

SESSION ADDRESS:

Alaska State Capitol
Juneau, Alaska 99801
Phone: (907) 465-3743
1-800-565-3743
Fax: (907) 465-2381



INTERIM ADDRESS:

600 E Railroad Avenue
Wasilla, AK 99654
Phone : 907-376-2679
Fax: (907) 373-4745

Representative Carl Gatto

August 10, 2007

Dear Craig,

I am forwarding to you information sent by BP that you might want to consider. Please call if you want to discuss issues considered in BP's response.

A handwritten signature in cursive script that reads "Carl".

Carl

STATE OF ALASKA

SARAH PALIN, GOVERNOR

411 WEST 4th AVENUE, FIRST FLOOR
ANCHORAGE, ALASKA
99501

**ALASKA NATURAL GAS
DEVELOPMENT AUTHORITY**

TELEPHONE: (907) 257-1347

June 19, 2007

To: Alaska Oil & Gas Conservation Commission

**Amendment to Rule 9 Pool Off-Take Rates
CO 341D for Prudhoe Oil Pool – Prudhoe Bay Field**

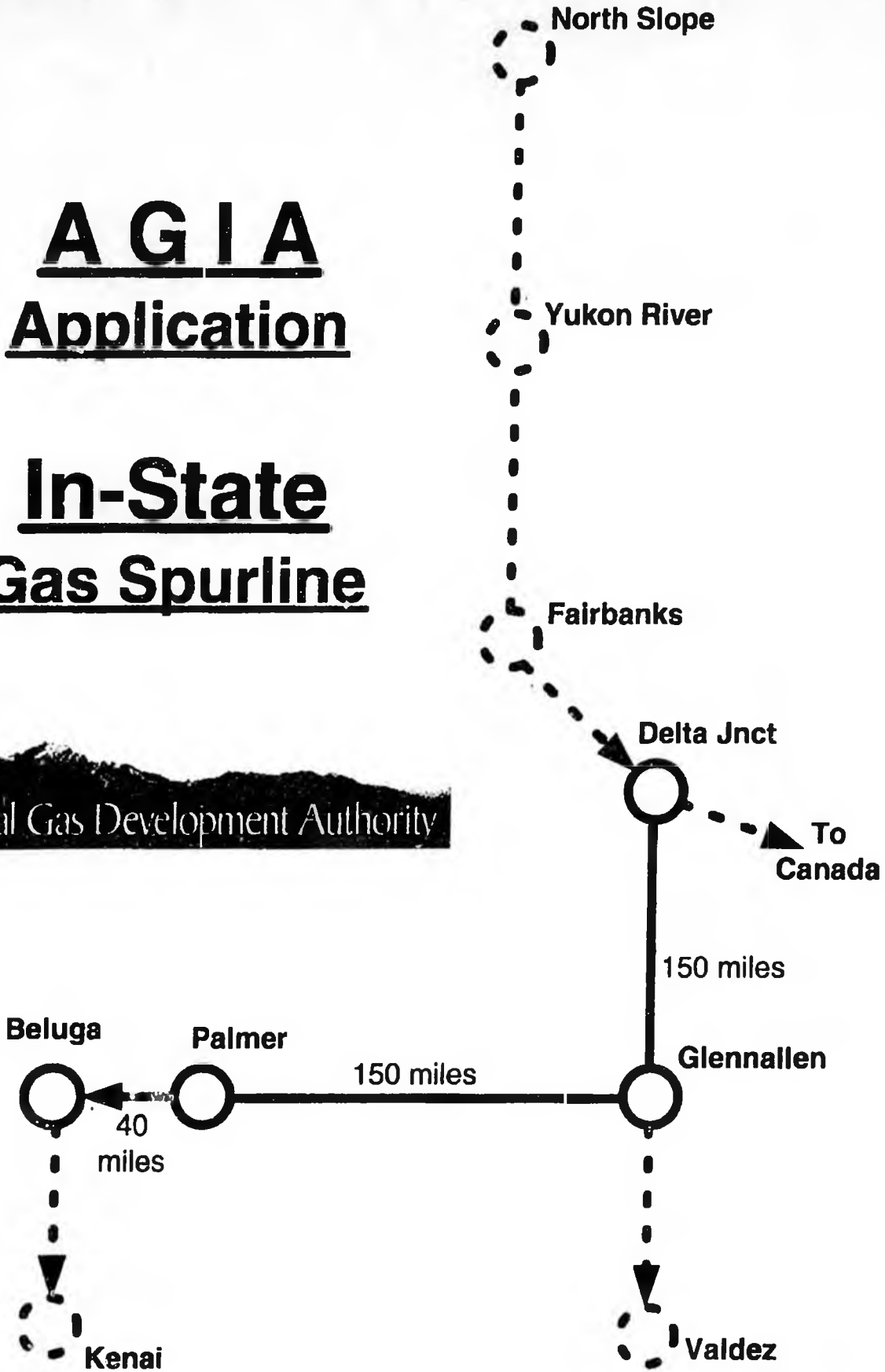
The Alaska Natural Gas Development Authority (ANGDA) is preparing an application in compliance with the provisions of the Alaska Gasline Initiative Act (AGIA) for an in-state gas pipeline linking Delta Junction to the Cook Inlet area through Glennallen. ANGDA will publicly offer this application, as an addendum, for inclusion in any major North Slope gas pipeline proposal. Our work schedule is targeted towards an October 1, 2007, submission deadline.

Our base estimate of 250 mmscfd (0.25 BCFPD) includes all residential needs for heat and electricity in-state, but excludes any existing or future industrial/export gas consumption. The State's 3 TCF of royalty gas is sufficient to satisfy these residential needs for 30 years. Industrial/export gas consumers will be included in an "open season" early next year and incorporated into the system design if commitments are made at that time. An addition of up to 1 BCFPD of industrial/export use will significantly lower the gas pipeline delivery costs for residential energy consumers.

A key part of the State's mandated application requirements under AGIA relates to the financing strength of the proposed pipeline project. ANGDA's preliminary contacts with major financial institutions, potential equity investors, and pipeline owner/operators, indicates that the regulatory availability of gas from Prudhoe Bay must be a certainty prior to any serious consideration of financial commitment.

AGIA
Application

In-State
Gas Spurline



Proposed Amendment to CO 341D Rule 9

Prior to committing gas for sale during a binding open season process, the operator must obtain approval from the Commission of a depletion plan that insures a greater ultimate recovery and prevents waste of oil and gas.

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501

Re: Inquiry into amending)
Rule 9 ("Pool Off-Take Rates").) Prudhoe Oil Pool
CO 341D, for the Prudhoe Oil Pool,) Prudhoe Bay Field
Prudhoe Bay Field)

July 10, 2007

REPORT OF THE COMMISSION INQUIRY
INTO AMENDING RULE 9 ("POOL OFF-TAKE RATES"), CO 341D,
FOR THE PRUDHOE OIL POOL, PRUDHOE BAY FIELD

On June 19, 2007, the Alaska Oil and Gas Conservation Commission ("Commission") held a public hearing (pursuant to AS 31.05.030(b)) to consider amending Rule 9 ("Pool Off-Take Rates") of Conservation Order ("CO") 341D for the Prudhoe Oil Pool, Prudhoe Bay Field, to require approval of a depletion plan prior to a significant gas offtake. This report presents the Commission's conclusions:

- No change in Rule 9 is necessary at this time.
- Prudhoe Bay operator must demonstrate, through existing reporting mechanisms, that they are implementing near-term strategies to maximize oil recovery prior to gas sales.

Rule 9 (which is among the Prudhoe Oil Pool pool rules that the Commission adopted in 1977) limits gas offtake from the Prudhoe Oil Pool to 2.7 billion standard cubic feet per day ("bscfd"). Because of the likelihood that Prudhoe Oil Pool gas will eventually be part of major gas sales, the Commission decided, in 2005, to investigate the need to update Rule 9 given the reservoir's development and information that has become available since 1977. Public hearings regarding revising Rule 9 were held on March 3, 2005, and May 19, 2005. In a December 5, 2005, report, the Commission noted that the Prudhoe Working Interest Owners ("WIOs") had agreed to provide access to their reservoir simulation and engineering studies so that the Commission could analyze the affects of different gas offtake rates and gas sales startup dates on total hydrocarbon recovery from the Prudhoe Oil Pool.

Based on reservoir model evaluations and studies provided by the WIOs, on February 15, 2007, Blaskovich Services, Inc., a reservoir engineering consultant, provided the Commission a confidential study on the potential impacts of major gas sales on hydrocarbon recovery from the Prudhoe Oil Pool ("Gas Offtake Study"). Oral and written summaries of the study were presented at a February 28, 2007, public hearing.

The Gas Offtake Study found insufficient information on which to justify increasing the offtake rate above 2.7 bscfd, but concluded that an early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons, but even greater volumes could be lost if gas sales

are too delayed. The study noted that offtake from gas sales is at least 8 years away. The study included several recommendations. First, before commitments to sell gas are made, to evaluate the potential impact of the offtake on total hydrocarbon recovery, a hydrocarbon depletion plan should be developed; the plan should take into account the offtake startup date, offtake rate, and liquid loss mitigation efforts. Second, to maximize total hydrocarbon recovery, the field should be prepared for gas sales through the implementation of near-term strategies that focus on increasing oil recovery prior to gas offtake and ensuring that facility and well downtime are minimized. Third, the Commission should receive periodic updates on the depletion planning efforts.

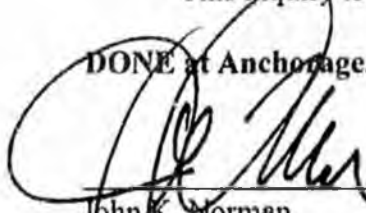
Following up on the recommendations of the Gas Offtake Study, at the June 19, 2007, public hearing, the Commission's staff proposed adding to Rule 9 the following: "Prior to committing gas for sale during a binding open season process, the operator must obtain approval from the Commission of a depletion plan that insures a greater ultimate recovery and prevents waste of oil and gas." The Commission's consultant, who prepared the study, explained how the proposed amendment was consistent with the recommendations. Also, the Commission received oral and written testimony on the proposed amendment from the field operator and members of the public.

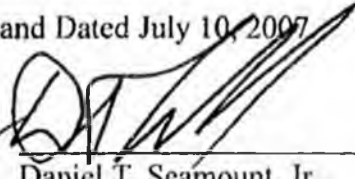
Based on the Gas Offtake Study and multiple hearings regarding Rule 9, the Commission has decided—at this time—not to amend the rule to require a Commission-approved hydrocarbon depletion plan prior to a gas sale. First, given that any major gas offtake as a result of a gas sale is still many years away, amending Rule 9 now to require such a plan is unnecessary; second, even in the absence of such a plan, the waste of oil and gas—including the waste of oil for gas—is prohibited pursuant to AS 31.05.095; third, the Commission already receives depletion plan-related information in the WIOs' annual surveillance report (which is required pursuant to CO 341D Rule 11), annual plan of development (which is required by the Department of Natural Resources ("DNR")), and annual field overview presentation (which is also required by DNR); and fourth, at the time (if ever) that an amendment is sought to increase the 2.7 bscfd gas offtake rate, Rule 9 can be amended to include a depletion plan requirement.

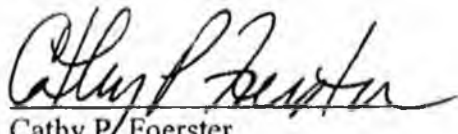
By not now taking action to amend Rule 9, the Commission retains the right to again consider requiring a Commission-approved hydrocarbon depletion plan prior to any major gas sales or to impose any other requirements that are consistent with the conclusions and recommendations of the Gas Offtake Study as part of any future amendment to Rule 9.

This inquiry is terminated.

DONE at Anchorage, Alaska, and Dated July 10, 2007


John K. Norman
Chairman


Daniel T. Seamount, Jr.
Commissioner


Cathy P. Foerster
Commissioner



BP Exploration (Alaska) Inc
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

August 2, 2007

BY FACSIMILE (without attachments) and OVERNIGHT DELIVERY

Hon. Carl Gatto
Hon. Craig Johnson
Co-Chairs, House Resources Committee
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

Re: Responses to Requests from June 7, 2007 Meeting of House Resources Committee

Dear Representatives Gatto and Johnson:

BP Exploration (Alaska) Inc. ("BPXA") appreciates the opportunity to respond to several requests from the June 7, 2007 meeting of the House Resources Committee. Please find below the answers to each of the Members' requests, which we have reproduced for your convenience.

Requests from Rep. Seaton

- Requests from September 2006 Memoranda

Rep. Paul Seaton posed four questions to BPXA in two memoranda, dated September 7, 2006 and September 14, 2006.¹

1. **I requested from BP verification of information [that] has circulated that the clean pigging was not done previously because TAPS Pump Station #1 could not handle the built-up volume of sludge with its filtration system and other arrangements were not made to alternatively handle that volume of sludge. I requested any BP correspondence with TAPS on the issue.**

Since BP is an owner of Alyeska, how can it justify not pigging the transit lines it operates in the Prudhoe Bay unit handling market oil while the same market oil in

¹ As Rep. Dahlstrom explained at the June 7 meeting, these requests were not originally addressed to BPXA in September 2006. BPXA was provided a copy of the requests shortly before the June 7 meeting.

TAPS requires a substantial expenditure and aggressive cleaning pig and smart pigging schedule as outlined [in the memorandum]? [Question from September 7, 2006 memorandum, "Transit Lines and TAPS Pigging Schedules"]

As I explained in my testimony at the June 7 meeting, the frequency of pigging^{2/} on the oil transit lines ("OTLs") in the Prudhoe Bay Unit ("PBU") and on the Trans-Alaska Pipeline System ("TAPS") may differ due to a number of factors, including operational requirements and for corrosion management reasons. As I described at the June 2007 meeting, BPXA runs maintenance pigs frequently on North Slope production lines and employs full-time crews dedicated to those pigging operations.

The sales-quality crude oil in the PBU OTLs is not "the same market oil" flowing through the TAPS. Indeed, the primary reason that the Alyeska Pipeline Service Company ("Alyeska"), which operates the TAPS, runs maintenance pigs at the frequency Rep. Seaton notes is that the TAPS market oil is a combination of crude oil from a wide number of different North Slope fields and operators. Some of these oils are prone to develop paraffin that can form on the interior of the pipeline. Over the approximately 800-mile length of the TAPS, this paraffin can, when the temperature drops, reduce the efficiency of the pipeline hydraulics system. Maintenance pig runs are thus required at more frequent intervals to combat the paraffin build-up. BPXA's approach to maintenance pig runs is consistent with Alyeska's flow regime strategy for lines on which, for example, paraffin build-up or temperature present issues. In comparison to the TAPS however, the PBU OTLs, which are only eight miles long on either side of Pump Station 1, carry crude oil that is relatively sweet, runs at higher temperatures, and does not contain high levels of paraffin.

As I further testified at the June 7 meeting, in-line inspections are typically undertaken to provide information as to the integrity of a line. BPXA has historically monitored the 16-mile section of the PBU OTL system via several inspection techniques, including in-line inspection and external ultrasonic inspection. It is an industry-accepted practice to use ultrasonic inspection techniques where the lines are readily accessible above ground and are relatively short in length. The TAPS system is, as noted, approximately 800 miles long, and approximately 50% of the line is buried below ground level. Those circumstances make in-line inspection the only practical means of inspection.

Regarding Rep. Seaton's statements about Pump Station #1, BPXA respectfully submits several points of clarification. First, cleaning pig runs were "done previously," *i.e.*, prior to the runs in 2006 to which Rep. Seaton appears to refer, on the PBU OTLs. Second, based on experience from those prior cleaning pig runs in the Eastern Operating Area ("EOA") in the early 1990s in which some scale flakes or chips collected in the screens^{3/} of Pump Station #1,

^{2/} "Pigging" encompasses three different types of activities: runs by cleaning pigs, runs by maintenance pigs (which are a type of cleaning pig that are used both to ensure that lines are clean and for other operational reasons), and in-line inspection (colloquially known as "smart pigging").

^{3/} Pump Station #1 does not have a "filtration system."

there was some discussion between BPXA and Alyeska in 2006 about the potential presence of solids^{4/} in future pigging runs.^{5/} Third, it is not the case that "other arrangements were not made" to address this potential issue. To the contrary and among other things, modifications were made to Tank 110 in 2006 to allow it to handle any solids that were returned as a result of pigging runs, and a series of runs were completed in 2006.^{6/} Finally, subsequent pigging runs did not result in a particularly high "volume of sludge." Indeed, Alyeska assessed the pigging returns sent to Tank 110 during those 2006 pigging activities and reported a total of only 32 barrels of sediment and 292 barrels of water recovered for all the EOA (Flow Station ("FS") 2-to-Skid 50) and Western Operating Area ("WOA") (Gathering Center ("GC") 1-to-Skid 50) OTLs.^{7/} These totals are well within the base, sediment & water ("BS&W") specifications for the amount of oil that has been shipped through those lines.

2. **We would like to see a copy and analysis of the pressure log data for the pigging operations on BP transit lines in 1992 and again in 2006. We would like to determine if any increased pressure needed to move a pig down a line with a lot of contamination built up could have caused or played a role in the subsequent pipeline leaks.** [Request from September 14, 2006 memorandum, "BP Transit lines pigging information request"]

This request appears to assume a condition that did not exist. As described in response to Question 1, Alyeska assessed pigging returns from the 2006 pigging activities on the EOA and WOA OTLs and reported minimal returns of sediment and water. Similarly, when BPXA maintenance-pigged the Lisburne Production Center ("LPC") OTL (another North Slope OTL not part of the PBU) in 2006, the runs returned minimal solids (less than 5 gallons) and revealed minimal damage.

BPXA does not believe that pressure in the lines played a role in the OTL leaks in 2006. BPXA's analysis of the pipeline operating pressures associated with its extensive pigging operations in the WOA and EOA OTLs in 2006 shows no significant increases in pressure

^{4/} For purposes of these responses, "solids" means material in the lines that contains both organic and inorganic matter.

^{5/} BPXA is providing correspondence (without attachments, which in many cases are voluminous) with Alyeska that it has identified regarding this issue. BPXA has not conducted a forensic search of correspondence but believes it has identified the principal communications on this matter. This correspondence is attached hereto as Exhibit 1 and bears the Bates labels BPXA-AKLEGIS000001-29.

^{6/} See, e.g., Letter from Jerry Brossia, State of Alaska Joint Pipeline Office, to Robert I. Shoaf, Compliance Officer for Alyeska, copying Nolan Heath, et al. (Sept. 27, 2006) (reflecting approval for Alyeska to modify Tank 110, as described) (attached hereto as Exhibit 2). This correspondence bears the Bates labels BPXA-AKLEGIS000030-31.

^{7/} See Letter from Joynor, Alyeska Vice President of Oil Movements, to Brossia and Michael Thompson, State of Alaska Joint Pipeline Office (Dec. 20, 2006) (attached hereto as Exhibit 3). This correspondence bears the Bates labels BPXA-AKLEGIS000032-43. BPXA did not pig the segment of the WOA OTL from GC2 to GC1; this segment (also known as "OT21") was instead removed from service and decommissioned.

Figure 2. EOA: FS2-to-FS1 OTL, hourly average pressure data overlaid with pigging events.

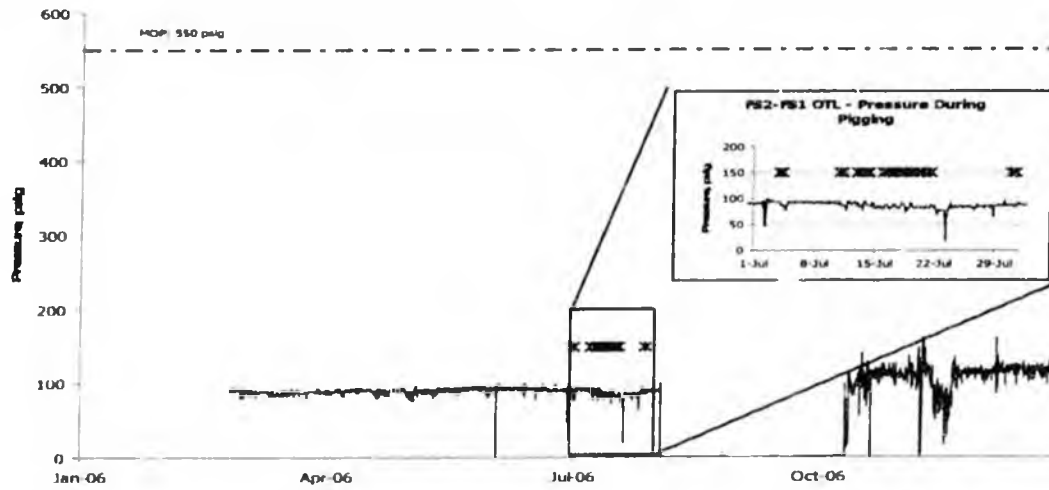


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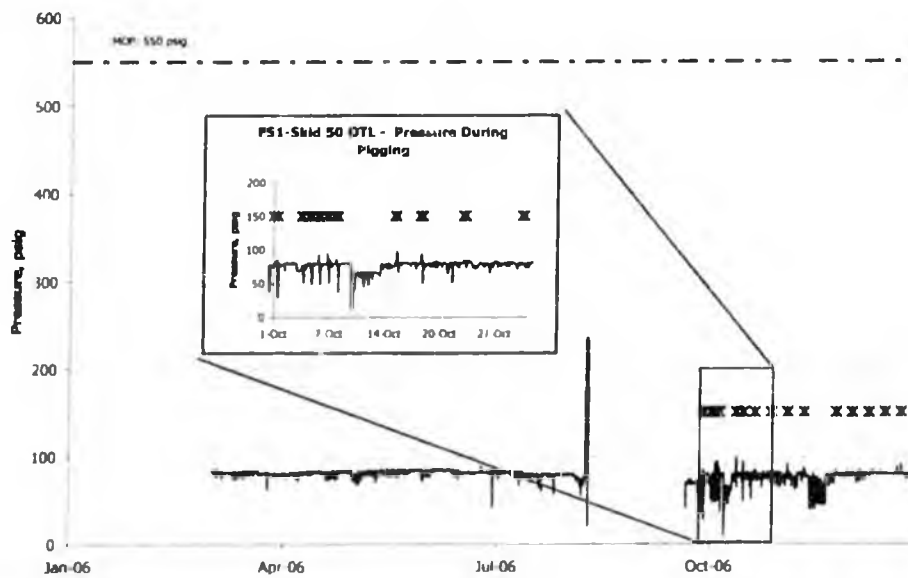


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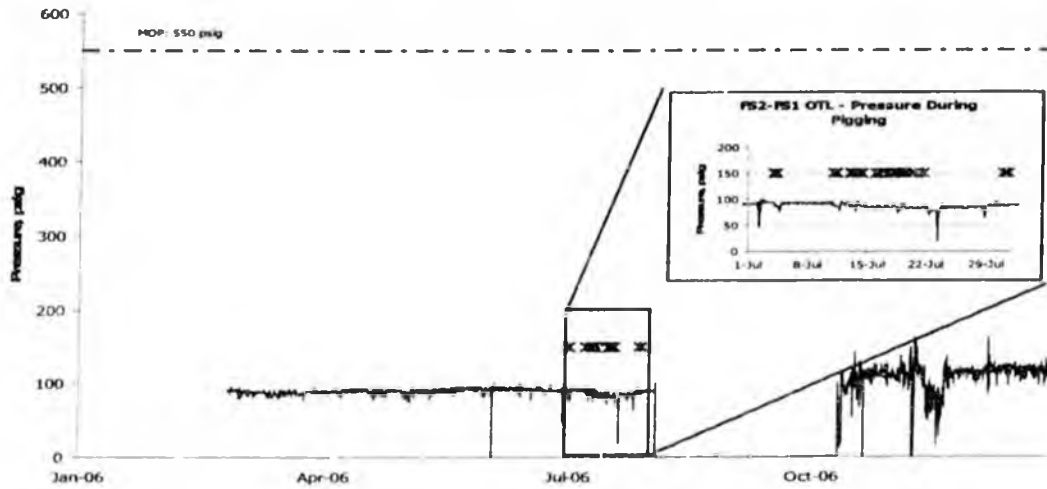


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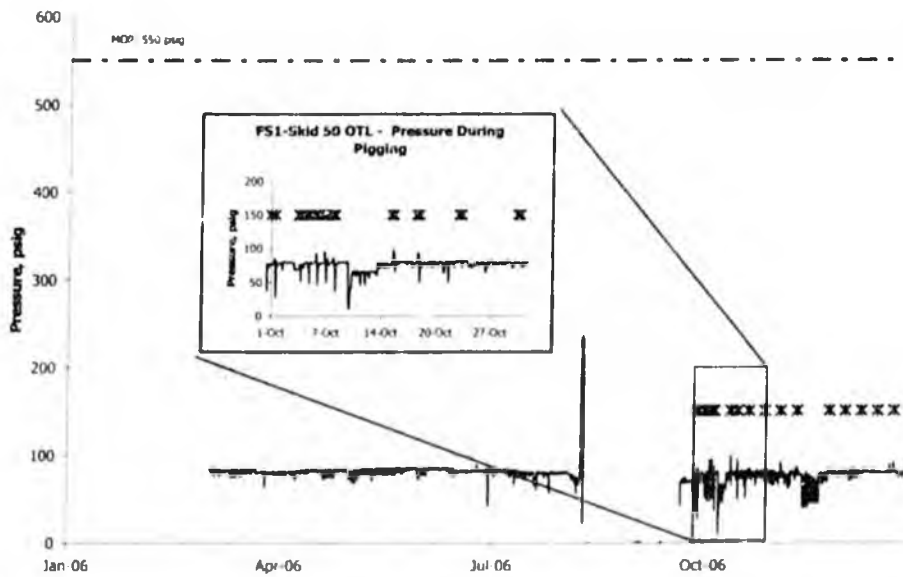
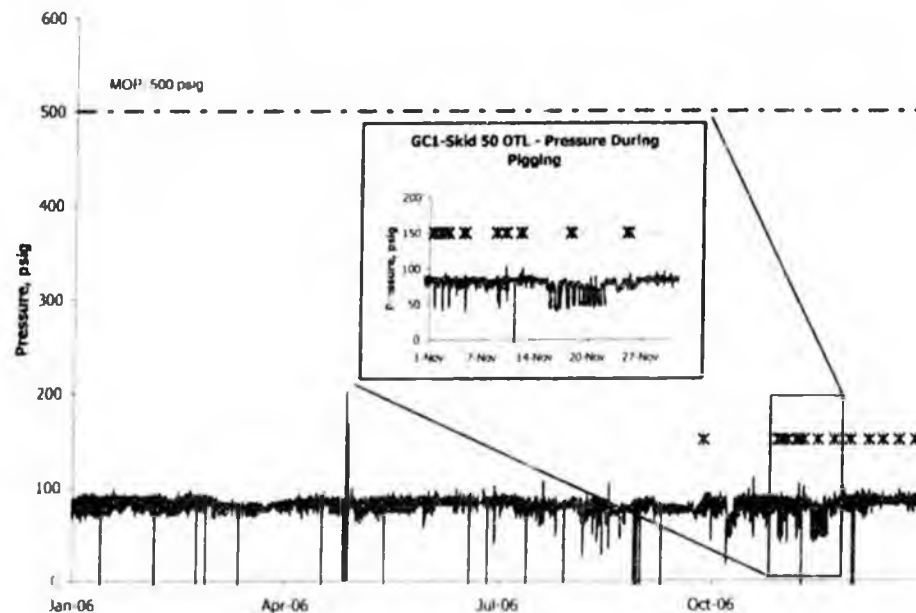


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3. Please provide the committee with a two-year summary of the pigging done on transit pipelines in fields that BP operates worldwide. Please specify which examples of the pigging frequency in other BP operated fields are similar to the Prudhoe Bay NS transit lines.

We have been provided information that standard industry practice is to pig often to prevent problems. We have been informed that each field has different oil and gas characteristics that require different procedures but nowhere to our understanding is regular pigging not done. If you have examples of such, please specify and provide details of the reasons for such a low maintenance determination. [Request from September 14, 2006 memorandum]

As Rep. Seaton notes, each field has different characteristics, including the type and quality of crude produced; the weather conditions and terrain in which the field is located; the level of pressure needed to move crude through pipelines; and whether the pipelines must be buried below ground or travel through water. The pipelines themselves are in turn specific to the field; among other things, pipelines differ in terms of metallurgy and size. These differences, in both fields and pipelines, are all part of the calculus that informs decisions about the maintenance procedures used on any given pipeline, including decisions whether and when to run cleaning and/or maintenance pigs and/or to conduct in-line inspections. As noted above in response to Question 1, BPXA's cleaning and maintenance pig data on the PBU OTLs show that there has been very little sediment build-up in them over time.

BPXA has previously explained that there are two different types of pipelines in the PBU that carry crude oil: OTLs, which carry sales quality oil downstream of processing facilities, and flow lines (sometimes also known as "production gathering lines"), which carry multi-phase flow from well heads to processing facilities. The leaks in 2006 occurred in the EOA and WOA OTLs, which are large-diameter, low-stress, above-ground lines. BPXA operates no other large-diameter, low-stress, above-ground OTLs and is not aware of any such lines being operated by any affiliate. Meaningful comparison to other lines of different sizes that are used in different service, under different conditions, and to transport oil of different quality and/or composition is thus not possible.

BPXA understands Rep. Seaton's statement regarding standard industry practice to refer to maintenance pigging. As BPXA has previously explained, it is not aware of any industry standard or recommended industry practice with respect to cleaning or maintenance pigging.

4. **Was the fact that the Prudhoe Bay transit lines were carrying much less than design volumes combined with the idea that the pipeline diameter could be reduced by sludge accumulation without increasing pump pressure or otherwise impacting the operational efficiency of the line a consideration in the determination not to clean or maintenance pig the transit lines?** [Question from September 14, 2006 memorandum]

BPXA has not identified any correlation between operational efficiency of the OTLs and the potential for reduced cross-sectional area, and that potential was not a consideration in the maintenance strategy of the OTLs. BPXA has also not observed any appreciable change in the operating pressure of the system due to the accumulation of solids.

The flow in the OTLs has naturally lost velocity over time as a result of the declining production of the field, and any change in cross-sectional area of the OTLs would likely have been masked by this natural decline in output. In any event, prior to the leaks BPXA saw no indications of restrictions in the line that might have led to reduced throughput.

BPXA's post-leak analysis bears out these observations. Even though BPXA understands, in retrospect, that the reduction in volume of oil may have contributed to the circumstances that led to the leaks in the OTLs in 2006, the reduction in the cross-sectional area of the lines due to build-up of solids was relatively minor during the 10-year period prior to the 2006 leaks. As discussed above in response to Question 1, cleaning and maintenance pigging of the OTLs in 2006 revealed very little sediment build-up over time.

- Oral questions from June 7 meeting

Rep. Seaton posed the following questions at the hearing on June 7:

5. What percentage of the lines that BP is operating in the Prudhoe Bay Unit will the 18 smart pig runs in 2007 encompass?

Of the 18 in-line inspections that BPXA has planned for 2007, 16 are being performed on PBU pipelines; the others are being performed on a Badami pipeline and a Milne Point Unit pipeline. These 16 PBU pipelines account for 10% (16 of 164) of all PBU pipelines transporting crude oil (both flowlines and OTLs).^{10/}

6. Has BP billed Conoco or Exxon for the repairs and the maintenance that arose from the shutdown, the bypass line and those repairs yet? If they have been billed, [has] that been turned down? If they haven't been billed, when [is BP] planning on billing for that?

BPXA's working interest owner partners, ExxonMobil and ConocoPhillips, have approved the funds and are making payments for the spill response, subsequent inspections, and bypass construction. BPXA has submitted an Authorization for Expenditure request for the OTL replacement to ExxonMobil and ConocoPhillips, and that request is under review. Neither ExxonMobil nor ConocoPhillips has refused to pay any bills sent to them regarding any of these activities.

Question from Rep. Johnson at June 7 meeting

7. Will the costs of replacement of the affected lines be treated as a tax deduction under [the Petroleum Production Tax] by BP?

BPXA has previously provided a written response to this question. On February 15, 2007, Doug Suttles, President of BPXA, submitted a letter on this subject to the Honorable Members of the Alaska State Legislature. A copy of that letter is attached hereto as Exhibit 4. This correspondence bears the Bates labels BPXA-AKLEGIS000044-45.

^{10/} The total number of pipelines does not include facility piping or well lines, which, due to the nature of their construction (*i.e.*, they are of smaller diameter and shorter lengths and include sharp bends), cannot readily be in-line inspected using current technology.

Question from Rep. Fairclough, who attended the June 7 meeting of the Committee, joined by Rep. Seaton

8. **Are the deconstructions of the affected OTLs being charged against the dismantlement, removal, & restoration ("DR&R") fund? If so, will that charge decrease the fund? How would such a charge affect the FERC and rate calculations in the future? Would such a charge result in the DR&R fund being hit twice, for removal of a portion of the line and for the expense of creating a new line?**

When oil and gas assets are constructed, an estimate of the costs for DR&R of those assets is established as a future obligation (or "liability") by the corporation owning the assets and recorded as a provision on its balance sheet. The DR&R provision is an accounting entry and does not represent the establishment of a specific "fund" or escrow account. When the assets (or a portion of the assets) are removed, the actual costs incurred in the related DR&R activity are charged against this provision such that the total DR&R provision for the assets (or portion of the assets) will decrease. When a new pipeline is installed, the DR&R provision is increased to reflect the new obligation associated with the new pipeline. Thus, in the case of the replacement of the PBU OTLs, the provision will be reduced with respect to the old pipeline and increased with respect to the new pipeline. This accounting treatment is in accordance both with U.S. Generally Accepted Accounting Principles and BPXA's internal accounting policy.

With regard to Rep. Fairclough's question about the Federal Energy Regulatory Commission ("FERC") and future rate calculations, the PBU OTLs are not common carrier pipelines and thus are not subject to FERC tariffs. The costs to remove and/or replace these OTLs will therefore not impact tariff rates.

* * *

These responses contain highly sensitive, private business information and documents. Accordingly, BPXA believes that the State is required to treat and maintain this letter and these documents as confidential under the commercial privacy protection afforded by Article I, Section 22 of the Alaska Constitution; AS 40.25.120(a)(4); and AS 40.25.120(b)(6). BPXA respectfully requests that the confidentiality of this letter and these documents be preserved and that, if you wish to consider whether any of this information or these documents should be made public, BPXA be provided 60 days notice prior to any such disclosure to any third party, including other governmental entities.

Hon. Carl Gatto
Hon. Craig Johnson
August 2, 2007
Page 10

Please feel free to call me if I may be of further assistance.

Sincerely,

 FOR
TONY BROCK

Tony Brock, Technical Director
BP Exploration (Alaska), Inc.

Attachments: as stated

cc: Hon. Charlie Huggins, Chair, Senate Resources Committee
Hon. Paul Seaton
Hon. Anna Fairclough (by overnight delivery only, without exhibits)

Exhibit

1

CORRESPONDENCE WITH ALYESKA RE: 2006 PIGGING OPERATIONS

Tab	Description	Bates Number(s)
1	E-mail chain entitled "GBP Oil Transit Line Pigging" (Mar. 27, 2006)	BPXA-LEGIS000001
2	E-mail from GPB, Prod Opt TL (BPXA) to J.D. Kling, Alyeska, entitled "Pig file comments OT21" (Apr. 15, 2006)	BPXA-LEGIS000002
3	Letter from Steve Marshall, President, BPXA, to Kevin M. Hostler, Alyeska President & Chief Executive Officer (Apr. 25, 2006)	BPXA-LEGIS000003
4	Letter from Hostler to Marshall, copying TAPS Owners Committee (May 12, 2006)	BPXA-LEGIS000004-6
5	Letter from Hostler to A.N. Bolea, BP Pipelines (Alaska) Inc., et al. (May 12, 2006)	BPXA-LEGIS000007-9
6	E-mail from Bruce J. Williams, BPXA, to Michael W. Joynor, Alyeska Manager of Oil Movements, copying Randal Buckendorf, BPXA, entitled "GR scan data for OT lines" (May 19, 2006 3:02 PM)	BPXA-LEGIS000010
7	E-mail from Per Wangstrom, BPXA, to Williams et al., entitled "Latest GPB Oil Transit Line Solids Loading Estimate" (May 19, 2006 3:18 PM)	BPXA-LEGIS000011
8	Letter from Joynor to Marshall, copying Kathy Zinn, Alyeska (May 22, 2006)	BPXA-LEGIS000012
9	Letter from Maureen L. Johnson, BPXA Vice President for Greater Prudhoe Bay ("GPB"), to Joynor (May 23, 2006)	BPXA-LEGIS000013
10	E-mail from Williams to Joynor, copying Brett W. Leach et al., entitled "Lisburne solids measurements" (May 31, 2006)	BPXA-LEGIS000014
11	E-mail from Joynor to Katharine Fontaine, copying Gregg E. Knutsen, entitled "Pigging Assessment Discussion" (June 2, 2006)	BPXA-LEGIS000015
12	Letter from Kemp Copeland, GPB Field Manager, to Joynor (June 6, 2006)	BPXA-LEGIS000016
13	Letter from Hostler to Marshall, copying Zinn (June 7, 2006)	BPXA-LEGIS000017-18
14	E-mail from Fontaine to Joynor, copying Williams, entitled "Final Solids information from BPXA" (June 22, 2006)	BPXA-LEGIS000019-20
15	Letter from Copeland to Joynor (June 27, 2006)	BPXA-LEGIS000021
16	Letter from Joynor to Johnson, copying Hostler et al. (June 29, 2006)	BPXA-LEGIS000022-23
17	Letter from Marshall to Hostler (July 24, 2006)	BPXA-LEGIS000024-25

CORRESPONDENCE WITH ALYESKA RE: 2006 PIGGING OPERATIONS

Exhibit I (con't)

Tab	Description	Bates Number(s)
18	Letter from Marshall to Hostler (Aug. 9, 2006)	BPXA-LEGIS000026
19	E-mail from Joynor to Ian G. Livett, BPXA, entitled "Existing level of tank bottom solids in Tank 110 at PS01" (Sept. 29, 2006)	BPXA-LEGIS000027
20	E-mail discussion among Perry A. Markley, Alyeska; Livett; and Joynor, entitled "APSC EOA S&W Results" (Oct. 30-Nov. 1, 2006)	BPXA-LEGIS000028-29

1

From: Joynor, Michael [mailto:JoynorM@alyeska-pipeline.com]
Sent: Monday, March 27, 2006 4:09 PM
To: Fontaine, Katharine
Subject: RE: GBP Oil Transit Line Pigging

I have asked the group to give me a couple of names so that we don't miss any communications with you. Should be able to tell you by Wednesday.

MWJ

From: Fontaine, Katharine [mailto:Katharine.Fontaine@bp.com]
Sent: Monday, March 27, 2006 2:05 PM
To: Joynor, Michael
Subject: FW: GBP Oil Transit Line Pigging

Mike,

Whom within your organization should I contact regarding the pigging operation mentioned below?

-Kathy

From: Rocereta, Michael D
Sent: Monday, March 27, 2006 10:21 AM
To: Williams, Bruce J; Zinn, Kathleen; Copeland, Kemp; Mike Joynor (joynorm@alyeska-pipeline.com); Johnson, James F (APS)

Cc: Swank, Gregory R; Fontaine, Katharine; Pomeroy, Glen
Subject: GBP Oil Transit Line Pigging

Kathy,

Please advise Alyeska Pipeline operations and OCC that in as early as 2 weeks from today GPB might start a regular program of maintenance pigging for the 3 GPB oil Transit lines:

Lisburne Oil Transit Line (From the Lisburne Production facility to Pump Station 1)
Western Operating Area Oil Transit Line (from GC-2 to GC-1 to Skid 50)
Eastern Operating Oil Transit Line (From FS-2 to FS-1 to FS-3-Skid 50)

We expect this program to continue indefinitely.

We will advise Mike Joyner 3-4 days before each pigging runs begin and we will advise Mike when each pig enters each line and when it is retrieved. Glen Pomeroy or Kathy Fontaine will coordinate communication between BP GPB Operations and Alyeska OCC.

Michael Rocereta
TAPS Delivery Manager
Office: 907-564-5257
Cell: 907-440-7922
Home: 907-696-4574

2

From: GPB, Prod Opt TL
Sent: Saturday, April 15, 2006 7:29 PM
To: 'KlingJD@alyeska-pipeline.com'
C.: Wangstrom, Per E; Fontaine, Katharine; Tucker, Hal E
Subject: FW: Emailing: Pig file comments OT21.doc

Doesn't look like the strainers were pulled at PS01 meter during the WOA oil transmission line pigging in 1998.

Mike

-----Original Message-----

From: NSU, CIC TL
Sent: Saturday, April 15, 2006 5:21 PM
To: GPB, Prod Opt TL
Subject: FW: Emailing: Pig file comments OT21.doc

No mention of removing strainers in what history Mark could locate...

-----Original Message-----

From: Petersen, Mark A
Sent: Saturday, April 15, 2006 5:16 PM
To: NSU, CIC TL
Subject: Emailing: Pig file comments OT21.doc

John,

Here are the "Pigging Database" comments of all the 98 pigging campaign on the OT21 line. There are a few references to the screens, however nothing mentions removing them. If you think this is pertinent information we can forward it on.

Mark Petersen
Pigging Operator
659-4682
Beeper x4236.....568

3

bp

Steve Marshall

President, Alaska

April 25, 2006



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99510-6612
(907) 564-5477

Kevin Hostler
Alyeska Pipeline Service Company
900 E. Benson Blvd.
Anchorage, AK 99508

Dear Kevin,

As you may be aware, on March 15, 2006, the Department of Transportation issued a Corrective Action Order to BPXA as Operator of the Prudhoe Bay Unit directing maintenance pigging of the three Prudhoe Bay Unit oil transit pipelines (Prudhoe Bay Western Operating Area, Prudhoe Bay Eastern Operating Area and Lisburne). Via this letter, BPXA requests Alyeska's assistance in carrying out this order and in managing any solids or other returns that are liberated via this maintenance pigging activity.

Maintenance pigging oil transit pipelines has been done in the past on each of these pipelines and is conducted from time to time on other North Slope oil pipelines. In every case, this involves sending a pipeline pig or a series of pigs that are increasingly aggressive in their cleaning capabilities through the pipeline. The pigs themselves are "caught" in receivers prior Pump Station One, but currently, there are no tanks or other facilities designed to contain solids or other "pigging returns" within the Prudhoe Bay Unit. Since these pipelines were last pigged eight or more years ago, we do expect elevated solids levels during these maintenance pigging runs. We do not have conclusive estimates of the volume from each line, but will be conducting gamma ray surveys beginning later this week to position ourselves to provide greater insight to Alyeska on this matter. Our Maintenance and Reliability Manager, Bruce Williams, has already been assigned to provide technical information to support any risk assessment Alyeska may wish to conduct in assessing solids management issues.

We have also briefly evaluated the potential of constructing tanks within the Prudhoe Bay Unit to collect solids or other pigging returns. A very high level review concluded that such construction would require a minimum of eighteen months to complete. As a result, we request Alyeska's support so that we may comply with the DOT order and accomplish smart pigging of all three lines during the summer of 2006.

Thank you for your assistance. Please contact me with any questions.

Sincerely,

Handwritten signature of Steve Marshall in black ink.
Steve Marshall



BPXA-LEGIS000003

4



P.O. Box 196660

ANCHORAGE, ALASKA 99519-6660

TELEPHONE (907) 787-8700

Kevin M. Hostler
President & Chief Executive Officer

May 12, 2006

Steve Marshall, President
BP Exploration (Alaska) Inc.
900 East Benson Blvd.
Anchorage, Alaska 99508

Subject: Receipt of Material from Non-routine Pigging of Producer Lines

Dear Steve:

A team of Alyeska engineers, oil movement specialists, and others have completed an initial assessment in response to your April 25th, 2006 request to help manage the pigging materials that result from BPXA's proposed pigging activities in the EOA, WOA and Lisburne POTLs. This letter summarizes results of that assessment and describes the basis under which Alyeska would continue working on this request.

Alyeska's evaluation of the potential impacts to TAPS facilities if this material is to be received, is to ensure the activities and resultant impacts of receiving pigging material from the connecting pipelines meet the following standards:

- Any pigging activities will not adversely impact safety, environment or TAPS integrity.
- Any pigging materials from these activities will not adversely impact the safe and efficient transportation of crude oil in TAPS, nor adversely impact TAPS crude oil quality.
- Anything TAPS does relating to this type of pigging activity must be done for any connector in the future, should the situation arise again, or a similar situation on a different connection.
- TAPS must be reimbursed for its costs, paid fair market value for the use of its facilities, and be provided assurances that the risks of taking the materials are borne by BPXA.

As such, Alyeska initiated an assessment on TAPS equipment, systems, and operations from a safety, environmental, integrity, compliance and legal perspective. The assessment teams were directed to evaluate the apparent potential impacts and/or hazards to TAPS if the proposed BPXA maintenance cleaning pig material from these POTLs is routed into TAPS.

Because of the potential impacts to TAPS from these pigging materials, the first conclusion of the assessment is that if possible BPXA should handle these materials without utilizing TAPS. As a result, we request BPXA undertake a thorough engineering and cost analysis of its best options to remove the solids into a BPXA facility before they enter PS 1. As explained below, with agreement from BPXA to reimburse our costs, Alyeska will initiate a similar analysis of the best options involving TAPS, for eventual comparison with the BPXA option.

Based upon our present assessment, Alyeska can not at this point approve receipt of the pigging materials into TAPS, either to the mainline or to a tank at Pump Station 1. With regard to the first option, our assessment evaluated transporting the pigging materials through the TAPS mainline and into the Valdez Marine Terminal. The introduction into TAPS of these pigging materials is expected to pose significant adverse risks, particularly to safety, systems integrity and the environment. These risks can not be mitigated to an acceptable level, and Alyeska does not intend to consider this option further.

Based on Alyeska's assessment of the second option, to route pigging materials to a breakout tank at Pump Station 1, Alyeska is not prepared at this time to approve this option. Alyeska is willing to continue to explore and develop this option. There are several sub-options within this general concept that could be further developed. Fully developed options will be compared internally, and with the BPXA options on the basis of effectiveness in protecting the safe and efficient transportation of oil, worker and public

BPXA-LEGIS000004

safety, integrity, environmental protection and regulatory compliance to determine whether a TAPS option is acceptable to Alyeska, the TAPS Owners, BPXA, and government agencies.

Alyeska's assessment of a PS 1 storage tank option indicates that it is possible, but not certain, that impacts could be mitigated to an acceptable level of risk. While not attractive to Alyeska or the TAPS system, with additional analysis and consideration provided by BPXA, this option could potentially be viable, if TAPS elects to accept the operational and associated legal risks. A thorough evaluation of all the various issues, risks and mitigation measures of this option would need to be completed to allow Alyeska to make a final decision and recommendation to the TAPS Owners. Important issues that need to be resolved are whether this option could be accomplished without negatively impacting the maintenance shutdown of TAPS in July, and the strategic reconfiguration project. Also, this option has the potential to impact TAPS oil shippers. Accordingly our plan is to further evaluate this option in close coordination with BPXA, the TAPS regulators, and TAPS Owners.

While further analysis could change it, the concept currently envisioned is as follows: TAPS would temporarily lease the use of a crude oil breakout tank at PS 1 and the upstream piping to BPXA. Under this approach, Alyeska would retain a necessary amount of operational control of these assets. All pigging materials would be routed from the BPXA operated POTLs pig runs directly into the leased tank and removed as cleaning pig runs are completed. BPXA would retain custody of the pigging solids and accompanying crude oil until the solids had been removed. Ultimately, only normal quality crude oil would be delivered to the TAPS mainline. Alyeska would reserve the right to use the leased facilities for unplanned conditions as well as certain defined (e.g., TAPS shutdown) conditions and BPXA would agree to manage the contents of the tank in a manner that ensures that TAPS potential needs could be met. When BPXA has completed its use of the piping and tank for receipt and removal of pigging solids, the facilities would be returned to Alyeska in a condition equal to, or better than, when transferred to BPXA through the lease.

The findings of Alyeska's TAPS Impact Assessment and our legal analysis support this recommendation.

If BPXA would like to pursue this further Alyeska proposes that we proceed as follows:

- A. Develop a funding agreement between BPXA and Alyeska to cover Alyeska assessment costs to date and costs in developing a detailed plan for the PS 1 storage tank option. This work will include, but not be limited to, preliminary design of facilities, assessment of issues, risks and potential variations on the option and preliminary review with the TAPS Owners, the JPO and regulators.
- B. Work together as follows:
 1. As a prerequisite for Alyeska moving forward with its analysis, we request BPXA to evaluate and document its best alternatives available for managing the pigging materials upstream of PS1. We need this information so that we can have an informed discussion with the TAPS Owners and our regulators about the best options to handle the pigging materials. We wish to be clear on an important point: even if, after analysis, use of a PS 1 tank appears to be the best option from a cost and timing perspective, it may not be acceptable from an operational, compliance and legal perspective.
 2. If this analysis produces a plan that meets all our criteria for acceptance, Alyeska will only proceed with the plan after we have a contract whereby BPXA agrees to bear the costs incurred by Alyeska and TAPS to accommodate BPXA's request and to put TAPS in a position to accept the pigging materials, including the costs of risk mitigation, and the fair market rental value of the facilities.
 3. Our agreement with BPXA must address all elements of this arrangement, including but not limited to an indemnity agreement whereby BPXA will provide full indemnification of Alyeska and the TAPS Owners for any liabilities that may arise from the decision to accept the pigging materials (including claims based on negligence, gross negligence, willful misconduct, or

May 12, 2006

Page 3

criminal acts). A demonstration of financial responsibility similar to other TAPS connectors would be required, along with other terms and conditions appropriate to this new agreement.

4. Commit to establish connection permits and agreements for the PBU and Lisburne connections. Although we will not require completion of the connection agreements before the pigging operations commence, Alyeska will require a written statement of intent to complete them by the end of 2006, recognizing that RCA approval may take longer.
- C. Alyeska will provide a full briefing to its regulators, in advance, on Alyeska's proposed action and all relevant circumstances and considerations affecting it.
- D. Alyeska will require a formal pigging plan from BPXA prior to receipt of GPB pigging materials into TAPS facilities.
- E. Alyeska will obtain any necessary approvals of the TAPS Owners after the above action items have been completed and before any pigging materials are allowed into TAPS.
- F. Alyeska will simultaneously adopt the foregoing points as a formal and non-discriminatory policy for dealing with similar requests (by BPXA and others) in the future.

If BPXA agrees to proceed on this basis, the following members of the Alyeska senior management team are designated for interaction with BPXA representatives:

Mike Joynor, Oil Movements Manager – technical and operational issues
Jordan Jacobson, VP and General Counsel – legal and contractual issues
Rob Shoaf, Compliance Officer – regulatory issues

Alyeska is prepared to proceed with this approach upon acceptance from BPXA. Please contact me if you wish to discuss this further.

Sincerely,



cc: TAPS Owners Committee

5



P O Box 196660

ANCHORAGE, ALASKA 99519-6660

TELEPHONE (907) 787-8700

Kevin M. Hostler
President & Chief Executive Officer

May 12, 2006

A. N. Bolea
D. C. Jones
M. P. Tudor
P. D. Allison
M. Purkey

BP Pipelines (Alaska) Inc.
ConocoPhillips Transportation Alaska, Inc.
ExxonMobil Pipeline Company
Unocal Pipeline Company
Koch Alaska Pipeline Company, L.L.C.

Subject: Receipt of Material from Non-routine Pigging of Producer Lines

This confirms our conversation last Monday concerning progress to date and a plan going forward regarding the receipt of pigging materials from the pigging of certain North Slope producer lines.

Background: In an April 25th, 2006 letter to Alyeska Pipeline Service Company, BP Exploration Alaska (BPXA) requested Alyeska's assistance in carrying out the DOT compliance order to accomplish In-line Inspection (ILI) of all three Produced Oil Transit Lines (POTLs) to include Lisburne (LPC), Eastern Operating Area (EOA), and Western Operating Area (WOA). Specifically, BPXA asked Alyeska's help by managing any solids or other returns that are liberated via the pigging activities. BPXA's letter notes that elevated solids levels are expected to result during these pigging runs. Based on historical records provided by BPXA, we understand that these POTLs have not been pigged since anywhere from 1993 for the WOA line to 1991 for the EOA line. There is no accurate means of determining the volume or quality of the pigging materials from each line. Due to the amount of time that has passed since the POTLs were last pigged, the estimated volume of accumulated solids within the POTLs is expected to be significantly greater than normally received during routine pigging operations. This may have a large impact to the overall TAPS crude quality.

Alyeska has conducted an evaluation of the potential impacts to TAPS facilities if this material were to be received. To accomplish this, Alyeska's guiding principles are to ensure that the activities and resultant impacts of receiving pigging material from the connecting pipelines meet the following standards:

- Any pigging activities will not adversely impact safety, environment or TAPS integrity.
- Any pigging materials from these activities will not adversely impact the safe and efficient transportation of crude oil in TAPS, nor adversely impact TAPS crude oil quality.
- Anything TAPS does relating to this type of pigging activity must be done for any connector in the future, should a similar situation arise again.
- TAPS must be reimbursed for its costs, paid fair market value for the use of its facilities, and be provided assurances that the risks of taking the materials are borne by BPXA.

As such, Alyeska initiated an assessment on TAPS equipment, systems, and operations from a safety, environmental, integrity, compliance and legal perspective. The assessment teams were directed to evaluate the apparent potential impacts and/or hazards to TAPS if the proposed BPXA maintenance cleaning pig material from these POTLs is routed into TAPS.

Based upon its assessment, Alyeska can not at this point approve receipt of the pigging materials into TAPS. Alyeska plans to ask that BPXA more fully develop its options to manage the pigging materials without using TAPS facilities. This is to protect TAPS from setting a precedent for shippers and connectors that would not be advisable. (BP's April 25th letter indicates that as of that date only a "high level review" of upstream options had been done.) While BPXA is doing that, if BPXA agrees to fund the effort, Alyeska will continue to develop an option of allowing BPXA to capture the solids in and remove them from either breakout Tank 110 or 111 at PS 1. Fully developed options will be compared internally and with the BPXA options, on the basis of their effectiveness in protecting the safe and efficient transportation of oil, worker and public safety, integrity, environmental protection and regulatory

BPXA-LEGIS000007

compliance to determine whether a TAPS option is acceptable to Alyeska, the TAPS Owners, BPXA, and government agencies.

Alyeska's assessment also evaluated the option to transport the pigging materials through the TAPS mainline and into the Valdez Marine Terminal. The introduction into TAPS of these pigging materials is expected to pose significant adverse risks, particularly to safety, systems integrity and the environment. These risks cannot be mitigated to an acceptable level. This option was not recommended by the assessment team.

In the PS 1 storage tank option, it is possible, but not certain, that impacts could be mitigated to an acceptable level of risk. While not attractive to Alyeska or the TAPS system, with additional analysis and consideration provided by BPXA, this option could potentially be viable if TAPS elects to accept the operational and legal risks associated with it. Alyeska's assessment identified several risks and potential mitigation measures in this option. A thorough evaluation of all the various issues, risks and mitigation measures of this option would need to be completed to allow Alyeska to make a final decision and recommendation to you. Important issues that need to be resolved are whether this option could be accomplished without negatively impacting the maintenance shutdown of TAPS in July, and the strategic reconfiguration project. Also, this option has the potential to impact TAPS oil shippers. Accordingly our plan is to further evaluate this option in close coordination with BPXA, TAPS regulators, and TAPS Owners.

While further analysis could change it, the concept currently envisioned is as follows: TAPS would temporarily lease the use of a crude oil breakout tank at PS 1 and the upstream piping to BPXA. Under this approach, Alyeska would retain a necessary amount of operational control of these assets. All pigging materials would be routed from the BPXA operated POTLs pig runs directly into the leased tank and be removed as cleaning pig runs are completed. BPXA would retain custody of the pigging solids and accompanying crude oil until the solids had been removed. Ultimately, only normal quality crude oil would be delivered to the TAPS mainline. Alyeska would reserve the right to use the leased facilities for unplanned conditions as well as certain defined (e.g., TAPS shutdown) conditions and BPXA would manage the contents of the tank in a manner that ensures that TAPS potential needs could be met. When BPXA has completed its use of the piping and tank for receipt and removal of pigging solids, the facilities would be returned to Alyeska in a condition equal to, or better than, when transferred to BPXA through the lease.

The findings of Alyeska's TAPS Impact Assessment and our legal analysis support this recommendation

Unless directed otherwise, Alyeska will proceed as follows:

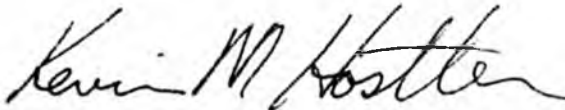
- A. Develop a funding agreement with BPXA to cover Alyeska assessment costs to date and costs of developing a detailed plan for the PS 1 storage tank option. This work will include, but not be limited to, preliminary design of facilities, assessment of issues, risks and potential variations on the option and preliminary review with the TAPS Owners, the JPO, and regulators.
- B. Work with BPXA as follows:
 1. Require BPXA to demonstrate that there is no reasonable alternative available for managing the pigging materials upstream of PS1.
 2. Require BPXA to bear the costs incurred by Alyeska and TAPS to accommodate BP's request and to put TAPS in a position to accept the pigging materials, including the costs of risk mitigation, and the fair market rental value of the facilities.
 3. Require BPXA to provide full indemnification of Alyeska and the TAPS Owners for any liabilities that may arise from the decision to accept the pigging materials (including claims based on negligence, gross negligence, willful misconduct, or criminal acts). A demonstration of financial responsibility similar to other TAPS connectors should be required, along with other terms and conditions appropriate to this new agreement.
 4. Work with BPXA to commit to establish connection permits and agreements for the PBU and Lisburne connections. It is not contemplated that this activity can be completed before the pigging operations commence.

Letter to Owners: Receipt of Material from Non-routine Pigging of Producer Lines
May 12, 2006
Page 3

- C. Alyeska will provide a full briefing to its regulators, in advance, on Alyeska's proposed action and all relevant circumstances and considerations affecting it.
- D. Alyeska will require a formal pigging plan from BPXA prior to receipt of pigging materials into TAPS facilities
- E. Alyeska will bring this matter back to the TAPS Owners after the above action items have been completed and before any pigging materials are allowed into TAPS.
- F. Alyeska will simultaneously adopt the foregoing points as a formal and non-discriminatory policy for dealing with similar requests (by BPXA and others) in the future.

Please let me know if you have any questions or concerns at this time.

Sincerely,

A handwritten signature in cursive script, reading "Kevin M. Hostler". The signature is written in black ink on a white background.

6

From: Williams, Bruce J
Sent: Friday, May 19, 2006 3:02 PM
To: 'Joynor, Michael'
Cc: Buckendorf, Randal
Subject: GR scan data for OT lines

Mike, per our discussion this morning here is the GR scan data for the OT lines.. Let me emphasis a couple of important points.

- This data is preliminary. We will be conducting additional analysis and processing to improve the accuracy and will forward that to you in about a week. Based on a field calibration test we believe the data is representative of sediment in the lines.
- Per Wangstrom is currently developing solids estimates for the lines based on these readings, their location and pipeline elevations. We should have these estimates later today or tomorrow.
- Additionally Per will summarize all the information that we've accumulated regarding evidence of line solids including thermal imaging and fluid velocity tests. For example, for the Lisburne line we have GR scan data, Thermal imaging, and fluid velocity tests that all present a consistent picture that indicates no to very low solids in the line. Taken as a whole, these data sets provide some confidence of our assessment of solids in the lines.

The attached spreadsheet includes the GR scan readings. I will send the athe areal photos with the locations and readings in a separate note due to the size of the files.



Gamma Scan
Tracker.xls (37 KB)..

Also, we are investigating your request on the skid 50 to PS1 line regarding inspection points between the battery limit valve and the insulation valve and should have an answer later today or tomorrow..

Pls call if you would like to discuss. Thanks.

7

From: Wangstrom, Per E
Sent: Friday, May 19, 2006 3:18 PM
To: Williams, Bruce J; Kurz, John; Rood, Robert C; NSU, CIC TL; JoynorM@alaska-pipeline.com
Cc: Swank, Gregory R; NSU, CIC Acuren Project Manager; NSU, CIC Mech Integrity Insp; NSU, CIC Fid Integ Ops; GPB SSEP Mech Piping Engr; GPB, FS3/GC3 Proc Engr; Susich, Mark L; Shaw, Susan M; Dengler, John M; Fode, Ethan A; GPB, Prod Opt TL; Foust, Nancy C; Hawley, Robert S; Hedges, Bill; Herod, Corey; Lammers, Joe J; Leach, Brett W; Blake, Jennifer J; Bruchie, James (Dave) D

Subject: Latest GPB Oil Transit Line Solids Loading Estimate

Folks,

Here are the latest GPB Oil Transit Line solids loading estimate. The estimate is based on the preliminary field data from the Acuren gamma-ray testing. Acuren still need to analyze the data in the office for about 40 hours to confirm the results. The analysis will be done next week.

Acuren will let us know if the final gamma-ray results will indicate if the top of the solids level on the bottom of the pipe is flat (horizontal) or has a contour along the pipe wall.

The preliminary gamma-ray data are consistent with the data from the Total Vapor Pressure (TVP) spike travel time, thermal imaging and transducer installation experience data point we have collected. The one exception is the temperature spike travel time test we conducted from FS1 to Pump Station 1, which indicated a relatively clean line, while the gamma-ray scans in all 8 locations indicate a very solids laden line. The travel time test is probably not very accurate, but it should be able to detect a line that is over a quarter full of solids. We will run another temperature spike travel time test from FS1 to Pump Station 1 to see if the data will be duplicated.

The gamma-ray data for the LPC line shows it to be pretty clean, which is consistent with the thermal images we have and the TVP spike travel time data. The line was also very clean when it was pigged in 1994. The line should have less than 15 cubic yards of solids.

The gamma-ray data for the 30" line from FS2 to FS1 shows an average of 4" of solids in the line. This is consistent with the thermal image we took of the line. It is also consistent with the experience we had when we installed the transducers for the leak detection system. We could not get a signal below 6" over the bottom of the pipe (which is consistent with gamma-ray reading by FS1).

<<GPB Oil Transit Lines Solids Loading - 5-19-06.ZIP>>

Per Wangstrom, PE
BRT Project Team Leader
BOC-113
(907) 659-4180 (office)
(907) 529-2944 (cell)

8



P.O. Box 199000

ANCHORAGE, ALASKA 99519-0000

TELEPHONE (907) 787-8700

May 22, 2006

Stevn Marshall
BP Exploration (Alaska) Inc
900 East Benson Blvd.
Anchorage, Alaska 99508

Subject: TAPS Impact Assessment of BPXA Pigging – Interim Report

Dear Mr. Marshall:

In an April 25, 2006 letter to Alyeska Pipeline Service Company (APSC), BP Exploration Alaska (BPXA) requested APSC's assistance in carrying out the DOT compliance order to accomplish In-line Inspection (ILI) of three Produced Oil Transit Lines (POTL) to include Lisburne(LPC), Eastern Operating Area (EOA), and Western Operating Area (WOA). Based on this request, APSC formed a TAPS Assessment Team comprised of subject matter experts to evaluate the potential impacts of receiving pigging solids from the proposed cleaning and inspection activities.

The Assessment Team conducted an evaluation of the potential impacts to TAPS facilities and operations if this material was to be received. Please find attached Alyeska Pipeline Service Company's (APSC) interim report that reflects the findings and recommendation of the team regarding the impacts of receiving pigging solids from the proposed BPXA cleaning and inspection pigging activities of the EOA, WOA, and Lisburne Produced Oil Transit Lines.

If you have any questions or comments regarding this information, please contact Kevin Hostler at 787-8449. Please copy me on your reply to this correspondence.

Sincerely,

Michael W Joynor
Manager Oil Movements

Enclosure(s): "TAPS Impacts Assessment of Receiving Pigging Solids from BPXA Produced Oil Transit Lines – Interim Report" Controlled copy # TIAR-IR 06-001

cc: Kathy Zinn

MS 528

BPXA-LEGIS000012

9

bp



BP Exploration (Alaska) Inc
900 East Benson Boulevard
PO Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

May 23, 2006

Mike Joynor
Alyeska Pipeline Service Company
P.O. Box 196660
Anchorage, AK 99519

Dear Mike,

Thank you and your team for your willingness to discuss operational issues surrounding maintenance pigging with BP Exploration (Alaska) Inc. (BPXA). This letter is intended both to respond to Kevin Hostler's May 12, 2006 letter regarding "Receipt of Non-routine Pigging of Producers Lines" and to update BPXA's preliminary April 25, 2006 request to Alyeska for assistance in managing solids. As Mr. Hostler requested, BPXA has initiated a thorough engineering and cost analysis of its best options to remove solids into a Prudhoe Bay facility from non-routine BPXA pigging operations where large volumes of BS&W are expected. Our plan is to work with your staff in the next few weeks to advance the option to collect these "non-routine" solids in a PSI storage tank as your letter suggests.

Importantly, as we also explained to Alyeska during our May 22, 2006 meeting on this subject, new preliminary data shows that the solids loading in certain of the Prudhoe Bay oil transit lines will be similar in nature to the other lines BPXA pigs and we calculate that the pigging effluent will meet all TAPS quality specifications. As a result, in cases where solids are minimal enough to meet quality specifications, BPXA believes that pigging should be considered "routine" and handled just like the other lines BPXA and the other North Slope operators pig. We are doing a final validation of the solids data this week and have committed to providing the results to Alyeska. We intend to propose a tentative schedule for proceeding forward with pigging the Lisburne oil transit line in the near future. We request your support of this and other routine pigging operations.

Sincerely,

Maureen L. Johnson
BPXA Vice President
Greater Prudhoe Bay

BPXA-LEGIS000013

10

From: Williams, Bruce J

Sent: Wednesday, May 31, 2006 6:40 PM

To: 'Joynor, Michael'

Cc: Leach, Brett W; Fontaine, Katharine; Swank, Gregory R; GPD, Prod Opt TL

Subject: Lisburn solids measurments.

Mike, per our conversation earlier today, here is the electronic version of the final processed GR scan data for Lisburn OT line. As we discussed, we haven't seen any significant changes in the Lisburn measurements for the preliminary (pre-processed) data.

The estimate of solids based on the average measurement of .54" is ~ 17 cu yds. The accuracy of the readings are +/- 1/2", so the actual amount could vary of course, but our best estimate remains the average of the readings.



Gamma



LPC-ALPS OT

sensation BL rev 2.gamma Scan Locatio

11

From: Joynor, Michael [mailto:JoynorM@alyeska-pipeline.com]
Sent: Friday, June 02, 2006 4:12 PM
To: Fontaine, Katharine
Cc: Knutsen, Gregg E.
Subject: Re: Pigging Assessment Discussion

Kathy,

As a wrap up with my core assessment team this afternoon, we developed a list of items that we will need on Monday in order to continue the evaluation and assessment of an initial pig run assessment on Lisburne.

These, by priority, are:

- 1) BPXA final draft of Lisburne POTL pigging plan including pig types, sampling plans, etc. (We will then review and return comments on Monday)
- 2) Information on solids characteristics as utilized in the gamma scan effort (Bill or Greg referred to these); and/or, any data on the solids typically removed at the processing facility
- 3) A blank copy of the current pig tracking/observations data template.
- 4) Draft of Site safety/spill contingency plans (Jeff Streit, APSC, will work with BPX to develop and forward this weekend)
- 5) Potential of slugging inhibitor in advance of the pig (Bill H / Greg with CIC)

Please give me a call on my cell phone this weekend so that we may discuss. The number is 301-5299.

Thanks.

Mike Joynor

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bp



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196812
Anchorage, Alaska 99519-6612
(907) 561-5111

June 6, 2006

Mike Joynor, Oil Movements Manager
Alyeska Pipeline Service Company
900 E Benson Blvd.
Anchorage, Ak 99508

Dear Mike,

Thank you and your team for your efforts in working with BPXA to provide assistance in assessing options related to completing pigging operations on the Lisburne Oil Transit Line (OTL).

You and your staff met with several BPXA representatives on Friday June 2, 2006, to review the pigging procedures and solids information in order to initiate pigging operations for the Lisburne OTL. During that meeting you requested several items from BPXA prior to commencement of the initial pigging of the Lisburne OTL. The requested items are as follows:

- BPXA's Lisburne OTL pigging plan including pig types, sampling plans, etc.
- Information on solids characteristics as utilized in the gamma scan effort and/or, any data on the solids typically removed at the processing facility
- A blank copy of the current pig tracking/observations data template.
- Draft of Site safety/spill contingency plans
- Potential of slugging inhibitor in advance of the pig.

We appreciate your interest and cooperation in providing comments on our draft plans. Attached to this letter is the requested information.

We plan to initiate the first cleaning pig operation of the Lisburne OTL on Thursday June 8, 2006. Upon completion of the initial run, we will collect solids for analysis per our attached plan. If you have any questions or concerns, please feel free to contact me at 564-5146.

Sincerely,

A handwritten signature in black ink, appearing to read 'Kemp Copeland', is written over the typed name.

Kemp Copeland
Greater Prudhoc Bay Field Manager

BPXA-LEGIS000016

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P. O. BOX 196660, ANCHORAGE, ALASKA 99519-8660 TELEPHONE (907) 787-8556 FAX (907) 787-8924

Kevin M. Hostler
President & Chief Executive Officer

June 7, 2006

Steve Marshall
BP Exploration (Alaska) Inc
900 East Benson Blvd.
Anchorage, Alaska 99508

Subject: BPXA Pigging – LPC POTL Initial Pig Run

Dear Mr. Marshall:

In a May 23rd, 2006 letter to Alyeska Pipeline Service Company (APSC), BP Exploration Alaska (BPXA) indicated it has acquired data which indicates that the quantity of solids in certain POTL's is such that BPXA believes pigging can be accomplished without causing significant negative impacts to TAPS. We have since received and reviewed this data as it relates to the Lisburne Production Center ("LPC") line. We believe that by following certain precautionary steps outlined below, APSC would not act imprudently by proceeding to coordinate with BPXA an initial pigging run of the LPC line. Then, based upon the results of that pigging run, future POTL pigging operations can be better evaluated.

We respectfully request your confirmation that BPXA will do the following:

1. Ensure compliance with all safety, environmental, regulatory, and spill response requirements.
2. Run one pig only at this time.
3. Use the least aggressive pig such as a two cup pig or a foam cup pig in the LPC POTL for the initial run.
4. Follow the pigging plan developed by BPXA (submitted to APSC on 6/5/06) and revised by APSC on 6/6/06.
5. Perform post pig run gamma scans on previously scanned piping locations between the LPC pig receiver and PS01 to determine if solids are accumulating in this section of pipe.
6. Share all data collection information from solids and liquid analyses and other observations (e.g. subsequent gamma scans on LPC POTL piping) needed to determine the quality and quantity of materials delivered to TAPS.

By following these requirements and procedures a successful initial pigging run of the LPC POTL can be expected. These plans are limited to the LPC POTL initial pigging activity. Any future pigging activities on LPC POTL are dependant upon a successful outcome of the initial pigging run and may require revisions to these procedures and plans based on the data collected from this initial effort.

Assuming a pig run of the LPC POTL is performed you should not assume that additional pigs, either the LPC, EOA or WOA POTL's will be acceptable. In particular, we do not anticipate that pigging of the EOA and WOA POTL's can be allowed in this fashion based on the findings identified in the TAPS Impacts Assessment Interim Report. Pigging of each individual transit line will be evaluated based upon its anticipated impacts to TAPS.

BPXA-LEGIS000017

Steve Marshall
June 7, 2006
Page Two

We will contact the appropriate regulatory agencies and finalize plans for the initial pig run. If you have any questions or comments regarding this information, please contact me.

Sincerely,

A handwritten signature in black ink, appearing to read "S. Marshall", written in a cursive style.

cc: Kathy Zinn, MS 528

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From: Fontaine, Katharine
Sent: Thursday, June 22, 2006 11:41 AM
To: Joynor, Michael
Cc: Williams, Bruce J
Subject: Final Solids information from BPXA

Mike,

Attached below is a tabulation of the final solids data collected from the Lisburne, EOA, and WOA lines. We will be happy to provide you a copy of the final Acuren report as well.

We look forward to reviewing this information with you on Monday. Please let me know if you would like to have a copy of the report earlier than our meeting, I am sure I can hand deliver you a copy.

Take care,

nathy

From: Williams, Bruce J
Sent: Tuesday, June 20, 2006 8:29 PM
To: Johnson, Maureen L; Swank, Gregory R; Bolea, Albert N; Buckendorf, Randal ; Fontaine, Katharine; Copeland, Kemp; Hedges, Bill; Leach, Brett W; Foust, Nancy C; Stash, Sandy M (bp); McKim, Bradley S; Herod, Corey; Beaudon, Daren J; Kurz, John; GPB, Prod Opt TL; Lagomarsino, James R
Subject: RE: Conversation w/ Stacey Gerard

All, here are the final solids estimates for the OT lines based on the GR scan.

It is important to reinforce that the margin for error from the GR scan is 1/2". Additionally, while all the data from the various techniques didn't line up directly, we saw general agreement, usually w/in -1". Bottom line is that we expect these estimates could vary by ~ 25-50 yd³ each.

I'll be on the slope tomorrow, but pls provide comments.

Segment	Est. solids depth (in) from GR Scan	Est. solids loading (yd ³) from GR Scan
LPC - PS1	0.4	11
FS2 - FS1	1	29
FS1 - SK50	0.6	24
GC1 - GC3	0.8	16
GC3 - SK50	1.9	70
Total GC1- SK 50		86
GC2 - GC1	2.8	147

Here are the key points associated w/ the estimates

- The basis for the solids estimates provided is a measurement from a Gamma- Attenuation Measurement Survey. This tool allows estimates of solids in the pipe based on the amount of

gamma absorption by the sediment in the pipe and the measurement of the resulting reduction in gamma radiation at the tool sensor.

- Prior solids estimates data submitted to Alyeska and DOT consisted of preliminary unprocessed data. Subsequent to the original data release, we have undertaken substantial data validation and calibration verification efforts for the Gamma Scan data collected. In follow up tests and analysis, it was discovered that the initial measurements were incorrectly interpreted due to a phenomenon known as secondary radiation. GR Tests were rerun a second and third time to verify the accuracy of the final measurement.
- While other methods were also used to estimate solids loading, the GR data is considered the most accurate. Accuracy of the GR data is considered to be +/- ½ inch This data has also been compared with UT, velocity survey, and thermography techniques. In general, the other techniques show agreement with the solids estimates from GR w/in about +/- 1 inch
- Additionally, recent pigging results from the Lisburn OT line verify that the GR data is representative w/in its expected margin of error. While the GR data indicated an average depth of .4" (+/- ½ inch) for an estimate of ~ 11 yd³ of solids, actual solids from the cleaning pigging appears to be on the order of about 1 yd³.

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bp



BP Exploration (Alaska) Inc.
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P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

6/27/06

Mike Joynor, Oil Movements Manager
Alyeska Pipeline Service Company
900 E Benson Blvd.
Anchorage, Ak 99508

Dear Mike,

Thank you and your team for your efforts in working with BPXA to provide assistance in assessing options related to completing pigging operations on the upstream section (FS2 to FS1) of the Eastern Operating Area (EOA) Oil Transit Line (OTL).

You and several of your staff met with BPXA representatives on Monday June 26, 2006, to review the pigging plan and solids information for the FS2 to FS1 section of the EOA OTL. As discussed our plan is to complete the following actions:

1. Proceed with pigging the FS2 to FS1 section, where we know there is a low volume of solids.
2. Collect liberated solids from the pig receiver at FS1 for analysis.
3. Decide how to proceed with pigging of the FS1 to Skid 50 section after analyzing the solids from FS2 to FS1 and assessing the impacts posed to TAPS.


During the 6/26/06 meeting you requested several items from BPXA prior to commencement of the initial pigging of the EOA OTL. The requested items are as follows:

- BPXA final draft of EOA OTL pigging plan including procedures, pig types, sampling plans, spill contingency plans, etc.
- Information on solids volumes as estimated utilizing the gamma scan effort. (This was provided to Alyeska during our meeting in the Acuren report).
- Overview of the volumes estimates and characteristics. (This was provided to Alyeska in a power point presentation, hard copy given to Alyeska personnel).

We appreciate your interest and cooperation in providing comments on our plans. Attached to this letter is the requested information that was not previously submitted.

We are planning on initiating the first cleaning pig operation of the upstream section of the EAO OTL on Saturday July 1, 2006. Upon completion of the initial run, we will be collecting solids for analysis per our attached plan.

Sincerely,


Kemp Copeland
GPB, Field Manager

BPXA-LEGIS00021

16



P.O. B. 196680

ANCHORAGE, ALASKA 99519-6680

TELEPHONE (907) 767-8700

June 29, 2006

Maureen Johnson
Vice President, Greater Prudhoe Bay
BP Exploration (Alaska) Inc.
900 East Benson Boulevard
Anchorage, Alaska 99519-6612

RE: Notice of BPXA Pigging on Upstream Portion of Eastern Operating Area Oil Transit Lines

Dear Maureen:

I received the letter of June 27, 2006 from Kemp Copeland in which BPXA states that it intends to commence pigging of the upstream portion (FS2 to FS1) of the Prudhoe Bay Eastern Operating Area (EOA) Oil Transit Lines (OTL) on Saturday, July 1, 2006. BPXA provided this information to Alyeska in the form of a notice, not in the form of a request for approval.

We find it encouraging that BPXA's expert consultants have concluded, after investigation, that the volume of pigging solids likely to result from this activity may be considerably less than originally estimated by BPXA. It is also encouraging that BPXA has developed a plan to monitor and assess these pigging solids while the pigging activity is in progress. Finally, it is encouraging that the pigging BPXA contemplates at this stage will all take place nearly five (5) miles upstream from the nearest TAPS facilities; and that BPXA had not yet decided on a course of action with respect to pigging solids that may already exist or that may settle out in the five-mile segment between the site of the forthcoming pigging activities and the nearest TAPS facilities.

However, we are disappointed that BPXA appears to be proceeding – even far upstream from TAPS – in a manner inconsistent with the May 12, 2006, letter from Alyeska's President and CEO Kevin Hostler to BPXA's President Steve Marshall. In that letter, Alyeska made several points clearly: We will not agree to accept any volume, concentration, or character of pigging solids directly into the TAPS main pipeline that impacts the safe and efficient transportation of crude oil by TAPS; we strongly prefer that BPXA handle these pigging solids upstream of TAPS. However, if necessary we are willing to work with BPXA on plans for the possible use of TAPS Pump Station One tankage for the handling of such solids, if that is the most reasonable course of action after BPXA investigates and explains its other alternatives. We also indicated that we require an agreement from BPXA regarding these pigging solids and their possible impacts on TAPS, including indemnification, financial responsibility, and cost recovery and reimbursement provisions.

The fact that the Lisburne OTL proved to have very little in the way of pigging solids, while gratifying, does not obviate Alyeska's expressed concerns and position regarding pigging solids from the Prudhoe Bay OTL. Similarly, neither BPXA's current and greatly reduced estimate of likely pigging solids from the Prudhoe Bay OTL nor the fact that BPXA at this stage is working far upstream of TAPS, while also reassuring, can obviate Alyeska's expressed concerns and position as set forth in our May 12 letter.

BPXA-LEGIS00022

June 29, 2006

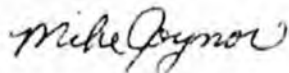
BPXA's decision to begin pigging the upstream EOA OTL on July 1 without the conditions of our May 12 letter being satisfied prompts us to reiterate that such pigging is not a TAPS activity nor does it involve TAPS facilities. It is a Prudhoe Bay Unit (PBU) activity carried out on PBU facilities for the PBU's benefit. We are not in a position to endorse or refute either BPXA's most current information supplied to Alyeska, or the implicit assumption that the risk of excessive pigging solids reaching TAPS as a result of your July 1 activities is very small. In any case, that risk is properly borne by BPXA as operator of the PBU, not by Alyeska, the TAPS Owners, TAPS itself, or third parties who rely on TAPS. Should BPXA's pigging activities result in any harm to Alyeska employees, TAPS facilities, third parties, or the environment, or should such activities lead to any permit violations or third party claims against Alyeska and/or the TAPS Owners of any kind, or any other costs, then Alyeska and the TAPS Owners will consider BPXA responsible and will require that BPXA fully indemnify and hold harmless Alyeska and the TAPS Owners.

Please note that the PBU connection facilities and PS1 are not designed to accommodate significant amounts of solids. In addition the PBU connection does not contain nor can it be easily modified to provide an open spool piece to prevent meter run obstruction or damage. Consequently, if BPXA's estimates prove to be wrong and significant amounts of solids obstruct the PBU line, the consequences could be very significant.

At the same time, Alyeska asks that BPXA abide by our May 12 letter (unless voluntarily modified by Alyeska in response to new pigging solids data provided by BPXA) with respect to any pigging activities on the Prudhoe Bay OTL that would be carried out nearer to TAPS facilities than those you intend to commence on July 1.

To make clear the dividing line between PBU activities, facilities, benefits and liabilities, on the one hand, and TAPS activities, facilities, benefits and liabilities on the other, Alyeska has also decided that, in the circumstances, it is now prudent and necessary to ask BPXA to execute a Connection Agreement for the PBU Connection. The draft Connection Agreement we provide you will be based on and reflect the most recently approved TAPS connection agreement, namely the Northstar connection agreement, which was signed by BP Transportation (Alaska) Inc., as well as the model connection agreement submitted to the Regulatory Commission of Alaska (RCA) prior to the Northstar connection agreement and approved by the RCA thereafter. We ask that BPXA promptly sign this Agreement. As usual in connection agreement matters, Alyeska on behalf of the TAPS Owners will then file the PBU Connection Agreement with the RCA for approval.

Sincerely yours,



Mike Joynor
Manager, Oil Movements Department

cc: Kevin Hostler, President
Jordan Jacobsen, General Counsel
Robert Shoaf, Compliance Officer
Jerry Brassia, JPO
Frederick Thompson, State Pipeline Coordinator

MS 528
MS 569
MS 502
411 West 4th Ave, 99501
411 West 4th Ave, 99501

17

bp

Steve Marshall
President, Alaska



BP Exploration (Alaska) Inc
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5422

July 24, 2006

Kevin Hostler
President & Chief Executive Officer
Alyeska Pipeline Service Company
P.O. Box 196660
Anchorage, AK 99519-6660

Subject: Update for the May 12, and June 29, 2006 letters from APSC

Dear Kevin,

I want to thank you and your organization for all the technical work and cooperation that Alyeska has demonstrated during our initial maintenance pigging runs for our oil transit lines (OTLs). The updated solids estimates, which are substantially lower than originally anticipated, have been shared with your technical staff, DOT, and JPO. The Lisburne OTL and the 30" segment of the Eastern Operating Area (EOA) OTL have been successfully pigged and smart pigged. We believe that maintenance pigging of our other OTLs can be successfully managed through the cooperation and joint technical acumen of our operations staff.

We provided Alyeska with an original pigging plan for our OTLs on April 25, 2006. Subsequent to that plan we have provided Alyeska with detailed line-specific plans prior to each of the Lisburne and EOA 30-inch pigging operations. A revised plan to clean and smart pig our OTLs is outlined below, with details explained further in the letter.

- Initiate and complete the cleaning of the FS1 to Skid 50 by November 2006
- Smart pig the FS1 to Skid 50 section immediately following completion of cleaning
- Install pig launcher at GC1 by October 2006
- Initiate cleaning and smart pigging of the downstream section of the WOA line downstream of GC1 by November 2006
- Install new upstream section of WOA (replacement piece for the OT21 section)
- Initiate routine pigging of the new OT21 section

Representatives of BPXA and Alyeska met on July 13, 17 and 29, 2006 to review solids handling options for pigging the 34-inch EOA section and the in-service WOA section. The options presented by BPXA and Alyeska to meet our November 2006 pigging target included:



BPXA-LEGIS00024

Kevin M. Hostler
Page 2 of 2
July 24, 2006

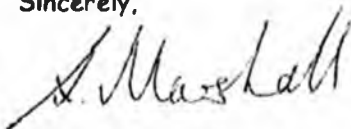
- 1) BP: Diverting the pigging envelope to FS3 through the GC3 - FS3 Fizzy oil line;
- 2) BP: Installing new piping from Skid 50 to FS3 and divert the pigging envelope to FS3;
- 3) APSC: Bypassing the meters to Tank 110 through new piping hot tapped from the main line to Tank 110 (requires tank penetrations); and
- 4) APSC: Connecting the 24" take-in-kind line at Skid 50 and extending the piping to Tank 110 (requires tank penetrations).

As we discussed, BPXA is actively pursuing Option 1, and Alyeska intends to continue to pursue Options 3 and 4. As you also know, the US Department of Transportation has specifically requested that TAPS options be explored via their most recent amended Corrective Action Order. We would like to reconvene to review the preliminary engineering and feasibility and construction timing on these options around August 1st.

BPXA agrees to develop a funding agreement with Alyeska to cover extraordinary costs associated the evaluation and handling the solids associated with pigging of the GPB OT lines. The funding agreement will include risk analysis conducted to date to assess the handling of solids at TAPS, preliminary engineering of solids handling projects, materials and labor contingent upon the decision to approve with one of the Alyeska solids handling options, and work related to activities associated with strainer monitoring and cleaning.. We will include in the funding agreement provisions covering indemnification for hold harmless obligations.

We appreciate the efforts your staff has made so far complete the Lisburne line cleaning and the FS2 to FS1 cleaning.

Sincerely,



Steve Marshall

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bp

Steve Marshall
President, Alaska



BP Exploration (Alaska) Inc.
500 East Benson Boulevard
P.O. Box 198612
Anchorage, Alaska 99519-6612
(907) 564-5422

August 9, 2006

Kevin Hostler
Alaska Pipeline Service Company
900 E. Benson Blvd.
Anchorage, AK 99508

Dear Kevin,

I'm grateful for your team's efforts to evaluate the pigging options into the PSI tanks. I wish to confirm BP's desire to move forward with the TIK pipeline extension on an expedited basis. Any time that can be shaved safely from the six-week installation estimate would help with restoring production sooner. I understand that our commercial and legal teams will work together to put the necessary agreements in place for BP to fully cover Alyeska's costs for this project.

Sincerely,

A handwritten signature in cursive script that reads "S. Marshall".

Steve Marshall



BPX-001-000000000000

BPXA-LEGIS00026

19

From: Livett, Ian G
Sent: Saturday, September 30, 2006 9:33 AM
To: Johnson, Maureen L; Copeland, Kemp; Kurz, John; Williams, Bruce J; Lagomarsino, James R; Fontaine, Katharine
Subject: FW: Existing level of tank bottom solids in Tank 110 at PS01

Not sure how accurate this is, but at least we have something from Alyeska on the level of solids in tank 110 before we started pigging the EOA 34" OTL.

Ian

From: Joynor, Michael [mailto:JoynorM@alyeska-pipeline.com]
Sent: Friday, September 29, 2006 4:40 PM
To: Livett, Ian G
Subject: Re: Existing level of tank bottom solids in Tank 110 at PS01

Ian,

Per your request, the following information on the existing volume of tank bottom in Tank 110 was provided by APSC Engineering:

Investigation into the "pre-existing" tank bottoms levels performed in early July indicated approximately one foot of solids in the bottom of the tank. This equates to approximately 4750 BBLS with a confidence of +/-25% for a tank of this size. Four thermograph sample points and a data run through IOL's SMART program simulation for the basis for these numbers.

Call if you have any questions.

Mike Joynor

20

From: Livett, Ian G
Sent: Thursday, November 02, 2006 10:09 AM
To: Williams, Bruce J; Kurz, John; Fontaine, Katharine; Swank, Gregory R; Lagomarsino, James R; Hauger, Wayne A; Ennis, John O
Subject: FW: APSC EOA S&W Results

Interesting comment from Mike Joyner!
Ian

From: Joynor, Michael [mailto:JoynorM@alyeska-pipeline.com]
Sent: Wednesday, November 01, 2006 5:23 PM
To: Livett, Ian G; Marklet, Perry A (APS)
Subject: RE: APSC EOA S&W Results

Ian,
We have completed the re-shoot and are completing the analysis. I hope to be able to discuss with you by Monday. I can say, preliminarily, there was a significant increase in the tank bottom level (heavy solids, etc.) resulting from the EOA pigging.
Mike Joynor

From: Livett, Ian G [mailto:Ian.Livett@bp.com]
Sent: Wednesday, November 01, 2006 5:17 PM
To: Markley, Perry A.
Cc: Joynor, Michael
Subject: RE: APSC EOA S&W Results

Thanks for this Perry. We are performing a comparison of this with our own sample analyses and will share the results with you.
Even though the sediment volumes are relatively small, have you attempted to re-shoot the level of solids in tank 110?
Ian

From: Markley, Perry A. [mailto:MarkleyPA@alyeska-pipeline.com]
Sent: Monday, October 30, 2006 3:40 PM
To: Livett, Ian G
Cc: Joynor, Michael
Subject: APSC EOA S&W Results

Ian, Mike Joynor asked that I send you the APSC EOA FS01 to TK-110 suspended S&W lab results obtained during TIK-Bypass activities. The attached results are for flowing samples collected from a point just downstream of the 24" to 12" reducer through an API probe inserted approximately 1/3 into the pipe. As mentioned within the attachment, the sediment results only reflect inorganic materials such as sand scale and rust which are a small part of the pigging solids received.

If you have any questions please do not hesitate to contact me,
Perry

APSC EOA FS01 to TK-110 Suspended S&W Lab Results											
Date	Run Number	Pig Type	Switch Times		TK -110 Receipt Total	Sediment		Water		S&W Total	
			Open	Close		Sediment %	bbbs	%	bbbs	S&W Total %	bbbs
9/30/2006	#1	Foam	11:47	13:16	10889	0.362	39.4	4.083	444.6	4.444	484.0
10/1/2006	#2	2 cup	11:55	13:38	10884	0.115	12.5	2.919	317.8	3.034	330.3
10/4/2006	#3	2 cup	11:45	12:57	9882	0.062	6.1	2.496	246.6	2.558	252.8
10/5/2006	#4	3 disc 2 cup	11:48	13:09	10953	0.049	5.4	2.031	222.5	2.080	227.8
10/6/2006	#5	6 disc	11:50	13:11	10873	0.033	3.6	2.656	288.8	2.690	292.5
10/7/2006	#6	6 disc brush	12:02	13:09	9014	0.042	3.8	3.813	343.7	3.857	347.7
10/8/2006	#7	Gauge	14:06	15:17	7719	0.036	2.8	5.934	458.0	5.970	460.8
10/15/2006	#8	Smart	15:46	17:04	8863	0.082	7.2	7.335	650.1	7.416	657.3
10/18/2006	#9	Smart	13:13	14:28	8121	0.029	2.3	0.982	79.8	1.011	82.1
Totals					87198		80.8		2972		3053

NOTE:

- ASTM D 4928 Determination of Sediment in Crude Oil and Fuel Oils by Extraction Methods
- ASTM D 4007 Determination of Water and Sediment in Crude Oil by The Centrifuge Method
- ASTM D 0473 Standard Test Method for Water in Crude Oil by Coulometric Karl Fischer Titration

The sediment results above reflect only the finer inorganic materials such as sand, scale and rust within the pigging solids received during the TIK-bypass / TK110 utilization. Only the smaller pigging solid particulates could be captured from the 1/2" sample port. Organic materials such as paraffin's, sludge and asphaltines that were liberated from the pipeline are not represented.

Exhibit

2



United States Department of the Interior



BUREAU OF LAND MANAGEMENT
411 West 4th Avenue
Anchorage, Alaska 99501
<http://www.ak.blm.gov>

SEP 27 2006

Letter No.: 06-091-RN
Case File Serial No.: F-12505
Section/Stipulation: 1.7.1 and 1.7.4
Facility Code: F4020
DD: N/A

Mr. Robert I. Shoaf
Compliance Officer
Alyeska Pipeline Service Company
P.O. Box 196660, MS 502
Anchorage, AK 99519-6660

Re: Request for Modification of NTP Condition of Approval 3(b) for Two 12-inch Diameter Hot Taps on Tank 110, Alyeska Letter No. 9805, dated September 25, 2006

References: Alyeska Letter No. 9476, dated August 11, 2006
Alyeska Letter No. 9512, dated August 16, 2006
Alyeska Letter No. 9553, dated August 21, 2006
Alyeska NTP Briefing for PS01 Tank 110 Hot Taps, August 23, 2006
Alyeska Letter No. 9566, dated August 25, 2006
JPO Letter No. 06-079-RN, dated August 25, 2006
JPO Letter No. 06-077-RN, dated August 29, 2006
JPO Letter No. 06-078-RN, dated August 29, 2006
Alyeska Briefing for Alyeska Letter No. 9705, September 11, 2006
JPO Letter No. 06-090-RN, dated September 19, 2006
Alyeska Letter No. 9792, dated September 21, 2006
Alyeska Letter No. 9737, dated September 26, 2006

Dear Mr. Shoaf:

Alyeska Government Letter No. 9805, dated September 25, 2006, requests modification to condition 3(b) of the Notice to Proceed (NTP) (JPO Letter No. 06-078-RN, dated August 29, 2006) for the hot tap welding on Tank 110 at PS01. Condition 3 of the NTP stated:

3) Prior to the PS01 bypass line and/or post-capture processing equipment becoming operational:

Mr. Robert I. Shoaf
Letter No. 06-091-RN

2

SEP 27 2006

Re: Request for Modification of NTP Condition of Approval 3(b) for Two 12-inch Diameter Hot Taps on Tank 110.
Alyeska Letter No. 9805, dated September 25, 2006

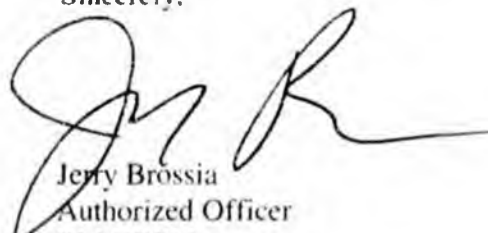
- a. Provide the JPO with the stress analysis for bypass line piping and piping/tank connections which consider all applicable in-service conditions. Analysis shall be stamped by a State of Alaska Registered Professional Engineer.
- b. Alyeska shall receive all applicable State Fire Marshal approvals for process equipment, locations, and enclosures.

Alyeska's request for modification to the NTP is approved and condition 3(b) is modified such that Alyeska can operate the PS01 bypass line prior to receiving the applicable State Fire Marshal approvals for process equipment, locations, and enclosures. In discussions with the State Fire Marshal's Office, they have no issues with the requested modification to the NTP. However, it should be noted that in accordance with State of Alaska laws and regulations, State Fire Marshal approval of the post-capture pigging materials processing system must be obtained prior to operating the post-capture pigging materials processing system. All other conditions of the NTP remain valid.

All terms, conditions and stipulations contained in the Federal Agreement and Grant of Right-of-Way for the Trans-Alaska Pipeline and Related Facilities, dated January 3, 2003 and the Renewal and Amendment of the Right-of-Way Lease for the Trans-Alaska Pipeline dated November 26, 2002 are incorporated by reference. The above does not abrogate the responsibility of Alyeska Pipeline Service Company to obtain any and all authorizations necessary for construction of the project under all applicable State and Federal laws and regulations.

For comments or questions related to the above, please contact Tom Johnson at 257-1339.

Sincerely,



Jerry Brossia
Authorized Officer
BLM/OPM

cc:

Nolan Heath, BLM
Joe Correa, BLM
Mike Thompson, ADNR
Tom Johnson, BLM
Doug Lalla, BLM
Jon Strawn, USDOT
Becky Lewis, ADEC
Ron Abernathy, BLM
Ron Watts, SFMO

BPXA-LEGIS00031

Exhibit

3



P.O. Box 186680, MS 575

ANCHORAGE, ALASKA 99519-0680

TELEPHONE (907) 787-8331

December 20, 2006

Government Letter No. 10642
APSC File No. 2.9

Joint Pipeline Office
411 West 4th Avenue, Suite 2
Anchorage, Alaska 99501

Attention: Jerry Brossia, Authorized Officer, BLM/OPM
Michael Thompson, Acting State Pipeline Coordinator, ADNRS/PCO

Subject: BPXA TAPS Bypass – Tank 110 Return to Normal Operation

References: JPO Letter No. 06-090-RN (MAC Issue #9786), dated September 19, 2006
JPO Letter No. 06-078-RN (MAC Issue #9595), dated August 29, 2006
JPO Letter No. 06-077-RN (MAC Issue #9594), dated August 29, 2006

Dear Mr. Brossia and Mr. Thompson:

By copy of this letter Alyeska formally notifies the JPO of its intent to return TK-110 to normal operations by COB Friday, December 22, 2006. It is our intention to meet and discuss this matter with you no later than Thursday, December 21.

The tank has been isolated after first receipt of BPXA pigging materials on September 30th, 2006. A total of 16 pigging events between BPXA's East Operating Area (EOA) and West Operating Areas (WOA) Units were directed into TK-110 at Pump Station 1.

Based upon thermographic analysis of the tank before receipt of pigging materials, after receipt of pigging materials, and at completion of processing activities, it has been determined that the tank is in, as clean or cleaner condition, than prior to the receipt of any pigging materials. As such, the tank is fit for a return to normal operations.

Demobilization of the processing skid equipment is proceeding and ongoing. The connection piping to BPXA's Skid-50 facility has been completely removed on both sides of the remnant Take-In-Kind line. The final clean-up and demobilization of all equipment and piping is anticipated to be completed in 2Q of 2007.

In keeping with previous correspondence on the subject matter, Alyeska is proceeding with the scheduled cleaning and internal inspection activities of TK-110 in 2Q 2007. Also the Design Basis Update, DB-180, will be modified to reflect the modifications to the tank in preparation for the subject pigging activities.

Please find a brief narrative of the processing events, thermographic analysis, and attendant material balance for this work.

If you have any questions or comments regarding this information, please contact myself (907) 787-8331 or Rob Annett at (907) 787-8167.

Sincerely,

Michael W. Joyner
VP Oil Movements

BPXA-LEGIS00032

Enclosures

General Process Description
Thermographic Analysis
Material Balance Pictorial

MWJ/rca

cc: Rob Shoaf	APSC	MS 502
Jeff Streit	APSC	MS PS01
Doug Ooms	APSC	MS PS01
Jerry L. Brossia	BLM/JPO	MS 600
Dan O'Barr	SOA/JPO	MS 600
F. Michael Thompson	ADNR/SPCO	MS 600
Ron Watts	SFMO/JPO	MS 600

Joint Pipeline Office
BPXA TAPS Bypass – TK-110 Return to Normal Operations

Government Letter 10642
December 19, 2006

Page 3

bcc: Cathy Zinn	APSC MS 528
Jim F. Johnson	APSC MS 548
Lorena Hegdai	APSC MS 850
Willie Hensley	APSC MS 542
Lee Schoen	APSC MS 854
Elizabeth Engle	APSC MS 534
Rob Annett	APSC MS 534
Jordan Jacobsen	ASPC MS 569

BPXA Piggina Solids Processing General Process Description

In March 2006, BPXA discovered internal corrosion in their transit lines from BPXA's East Operating Area (EOA) and West Operating Area (WOA) facilities. This resulted in their need to clean the internal surfaces of the transit lines through the use of scraper pigs in preparation for inspection with instrumented corrosion detection pigs. BPXA estimated that the cleaning would require 60 pig runs and would generate over 1570 cubic yards of solids, wax and/or asphaltenes. BPXA also anticipated the materials would contain approximately 15% water. Based on BPXA's estimates, Alyeska conducted an assessment on the impact to TAPS equipment that this amount of acute solids would have. This assessment determined that the materials should not be directly pigged into TAPS without being processed to remove excess water and solids; and the JPO agreed.

After completing research of possible options for how to handle the pigging solids, BPXA decided to utilize Tank 110 at APSC's Pump Station 1 to capture and retain the pigging materials. APSC would process the captured pigging material from Tank 110, return on-spec oil to TAPS, and dispose of the solids and water separated by the process.

APSC designed and assembled pigging solids processing equipment during the September timeframe with processing capacities that were aligned with the quantities of materials that BPXA anticipated transferring to Tank 110. The advanced staging of the equipment was required to manage the expected large volumes of solids anticipated, based on the BPXA estimates, and to maintain the viable utilization of the limited capacity of Tank 110 even with decanting capability. The system assembled included: jet mixers installed on Tank 110 as well as a processing skid comprised of two spiral heat exchangers, two decant style centrifuges to remove the bulk solids, two disk stack centrifuges to separate the oil and water, a large solids thermal processor, an extensive vapor handling system as well as a granular activated carbon water treatment system.

During October and November, BPXA cleaned the WOA and EOA transit lines through a total of 16 pigging events. The transfer of the pigging materials from Skid-50 to Tank 110 was accomplished via a temporary pipeline, designed and constructed by APSC for this specific purpose. Baseline thermographic analysis conducted on the tank prior to acceptance of BPXA pigging materials indicated that approximately 4730 bbls of tank bottom material had accumulated in the tank over the course of 9 years of service.

After the pigging events were completed, thermography estimates placed the total volume of pigging solids received in the tank at approximately 11,720 bbls of solids material, comprised largely of wax with trace amounts of sediment. This estimated volume does not distinguish between received materials and ongoing precipitation of wax within the tank. However for the purposes of the project this volume was used as a baseline condition.

Based on information provided by BPXA, it was estimated that the solids materials consisted of 50% solids, 35% asphaltenes and 15% water. A characterization of the waxy material received in Tank 110 was attained by vertical profiling and laboratory analysis by the Analytical Services group. This activity was performed after the solids were suspended using the jet mix system. The thermography analysis, in conjunction with vertical profile data, and subsequent material balance, indicated the solids from the BPXA pigging contained only 292 BBL of water and 32 BBL of sediment or 0.27% sediment and 2.5% water, emphasizing the high wax content of the pigging material and its eventual recovery as solubilized hydrocarbon. The water and solids recovered by the process will be shipped off-site for disposal pending analytical results. The recovered crude oil was returned to TAPS through the process.

Upon initiation of the pigging activities, Tank 110 was isolated from normal service. The tank level continued to rise as the pigging trans-mix from each pig run was introduced into the tank. In

order to manage the crude oil level within the tank, decanting was performed from the 10-foot level when lab data indicated that crude oil quality at that level met the BS&W specification required by the TAPS operating agreement. Management of the tank level continued throughout pigging operations by decanting from the 10-foot level and monitoring the quality of the crude to TAPS. The ability to decant on-spec oil throughout the receipt of all pigging events was an early indicator that the quality of the received material was significantly lower in solids than expected. No treatment of received solids was necessary during the pigging process and the entire EOA and WOA pigging material volume was contained within Tank 110 prior to the start-up of the processing system.

The pigging was completed later than initially estimated by BPXA. This coupled with a 45-day delay in securing an air quality permit for the construction and operation of the Pump Station 1 pigging material treatment skid drove the start of material processing out into early November. The late start pushed execution of the process into a season with ambient temperatures that dipped to as low as -25° F. The cold ambient temperatures caused the tank product temperature to become the critical element to manage. Colder tank temperatures hampered the project team's ability to move and process the pigging materials. Without the beneficial introduction of hot crude oil in the tank the product temperature within the tank would continue to drop to the point that wax precipitation occurs. Higher tank temperatures were achieved by the repeated introduction of hot crude oil into the tank. By elevating the tank temperature in conjunction with fluidization, the project team was able to keep the wax solubilized and mitigated its further accumulation in the tank. Prior to decanting the product was laboratory tested at the decant level for water and sediment to assure a suitable product was introduced into TAPS.

Maintaining the decanted crude on-spec was achieved by effective control of the jet mix energy and frequent laboratory testing. This resulted in the need to establish optimal operating regimes that provided adequate suspension and sheering of the accumulated wax with the entrained solids and water to provide suitable feed to the processing skid, while simultaneously allowing "co-processing" of on-spec crude from the 10-foot decant line enabling additional hot crude oil to be added for temperature control. This processing "balancing act" was critical for the effective management of the three key elements (temperature, mixing energy, dissolving of wax) required to achieve the goal of recovering the crude oil from the pigging solids without returning the entrained solids and water.

The colder ambient temperatures created other difficulties with the ancillary piping that fed the process skids. All feed, water and return lines had to be heat traced with electrical tracing or glycol heat lines. Tank water draw nozzles had to be heated with hot air to keep the nozzles thawed and free of ice. Walking and driving surfaces required constant maintenance to keep them free of ice and safe. Emergency drain down plans and procedures were developed to accommodate an emergency shutdown for high wind and extreme temperature events that occur at Pump Station 1 during this time of year.

The processing equipment was started after the pigging operations were complete and all of the regulatory approvals, including the ADEC air quality permit for the processing activity, were received. The process system required a number of modifications to accommodate the weather encountered due to BPXA and permitting schedule delays, quality variances between what was actually received versus what BPXA had told APSC to anticipate and falling temperatures of the material in the tank. Process procedures were developed to allow a low draw off line tank from the water draw valves (<1 foot elevation) to more effectively separate water and sediment from the crude oil.

The additional process modifications that allowed for simultaneous or independent decant and processing of material from the 10-foot decant line or the 6-inch water draw valves. When the tank levels dropped below the upper decant elevation and only the two 6-inch water draw points could be utilized, the material could be routed to either processing or decanting dependent on the material quality based on laboratory sampling. APSC Analytical Services continued to test for

BPXA Pigging Solids Processing
General Process Description

BS&W on the crude oil feed to the process and also on the product returning to TAPS. It was determined that the material feeding the processing skid was on-spec a majority of the time and could be effectively controlled with adjustment to the fluidization jets. This enabled both decanting and processing to be utilized to off-load saleable crude oil into TAPS. When the material was on-spec decanting was employed, when the material did not meet specification then the 6-inch water draw feed was routed to the processing skid to attain a product which consistently met the required quality specification.

This co-processing approach proceeded with intermittent hot crude oil refills to the tank, fluidization or jet mixing of the tank contents and analytical testing of the product quality. Analytical Services also performed periodic vertical profiling of the tank to define the variation of the material quality across the tank depth and established the required processing volumes to return Tank 110 to "on-spec" status. Thermographic evaluations were employed to help identify the amount of wax that had been suspended and sheered/dissolved into the warm crude in the tank.

A comprehensive material balance that included merging data from thermographic analysis, vertical BS&W profiles, processing skid inlet and outlet water and solids, etc. was utilized to determine the efficiency of the hydrocarbon recovery and solids / water removal system. The analysis indicates that virtually all of the 292 BBL of water and 92% of the 32 BBL of sediment that entered Tank 110 as pigging solids were removed from the oil processed through the skid. The jet mixing unit was able to shear all of the pig wax that entered allowing it to dissolve with the warm crude introduced into the tank. The decant system was on-spec over 90% of the time. Infrequent excursions were always held very close to the target limits and rapidly controlled through effective use of jet mixer energy.

The reintroduction of dissolved wax as recovered hydrocarbon through either the decant line or the processing skid was directed into TAPS through a local connection adjacent to the tank. The volume of material commingled with the ongoing TAPS stream was typically less than 3% of the total TAPS throughput over the course of the project.

The processing of the pigging solids was successfully executed in less than 20 processing days under extremely challenging weather conditions. The tank isolation valves and attendant piping to the tank were back-flushed to clear them of any accumulated pigging material prior to cessation of processing. This ensured that every attempt was made to clean and process any pigging materials introduced into the tank. The final vertical profile results indicated that even at the lowest levels within the tank that the tank met crude oil quality specifications. The actual values are depicted in Table 1.

Table 1 – Final Vertical Profile Laboratory Data

Tank Level	%H2O v/v	%Sed v/v	Total %S&W v/v
1.0'	0.213	0.015	0.228
2.0'	0.211	0.006	0.216
3.0'	0.215	0.012	0.227

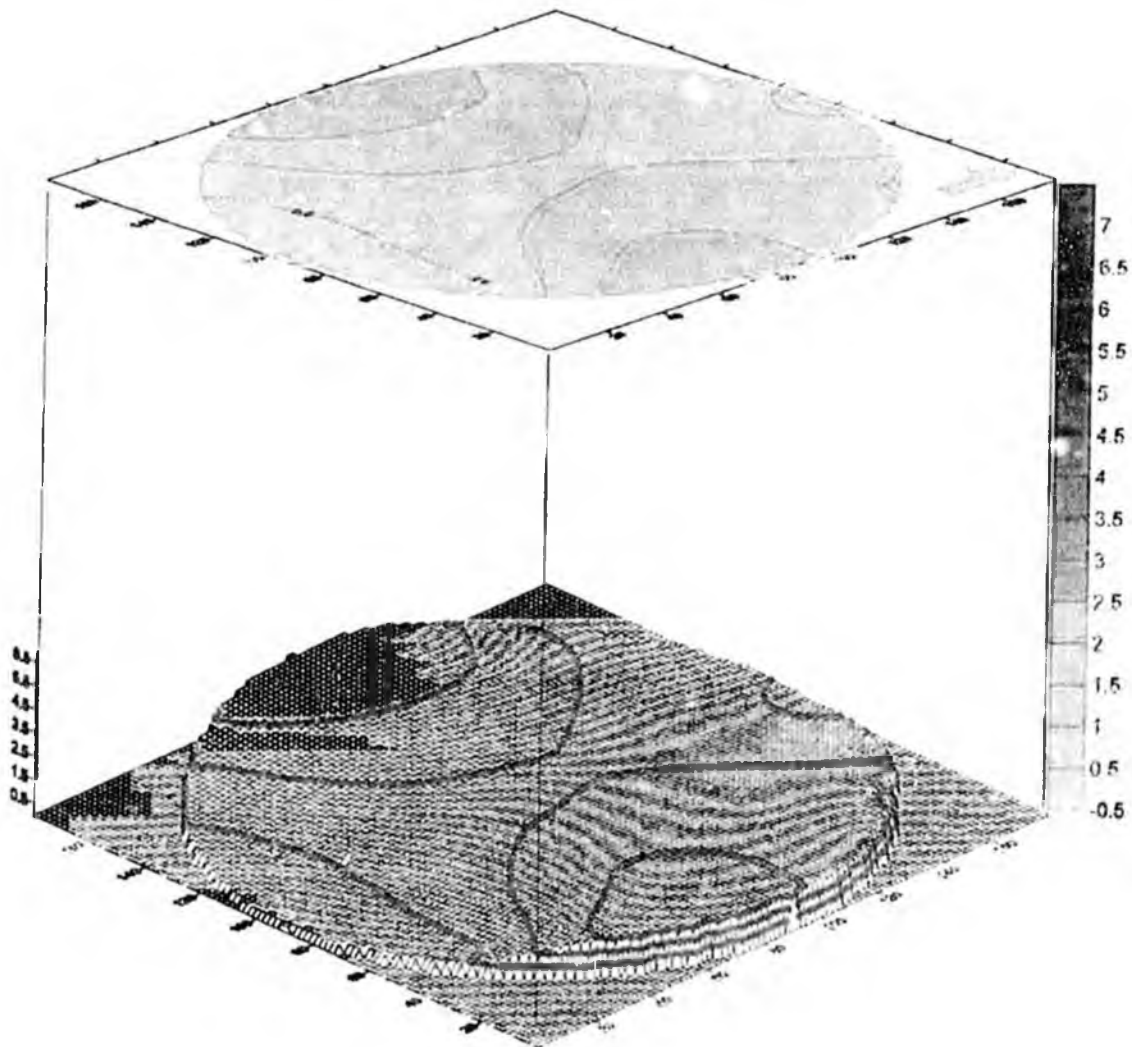
Based upon all laboratory and thermographic analyses the tank is as "clean or cleaner" than before the start of BPXA's pigging activities. As such the tank was deemed ready to be put back to normal operations on Thursday, December 14th, 2006. Processing equipment demobilization followed immediately and is ongoing.

TK-110 Thermographic / 3-D Fluid Dynamic Modeling
Initial Tank Bottoms Profile Prior to Pigging Project

Tank Bottoms level prior to any crude or pigging slurry transfer to tank. This is the "hardpan" or very solid wax layer present in the tank resulting from periodic service and associated wax precipitation.

Alyeska 110 Tank (ANS Crude) - Pre Jet Mixing

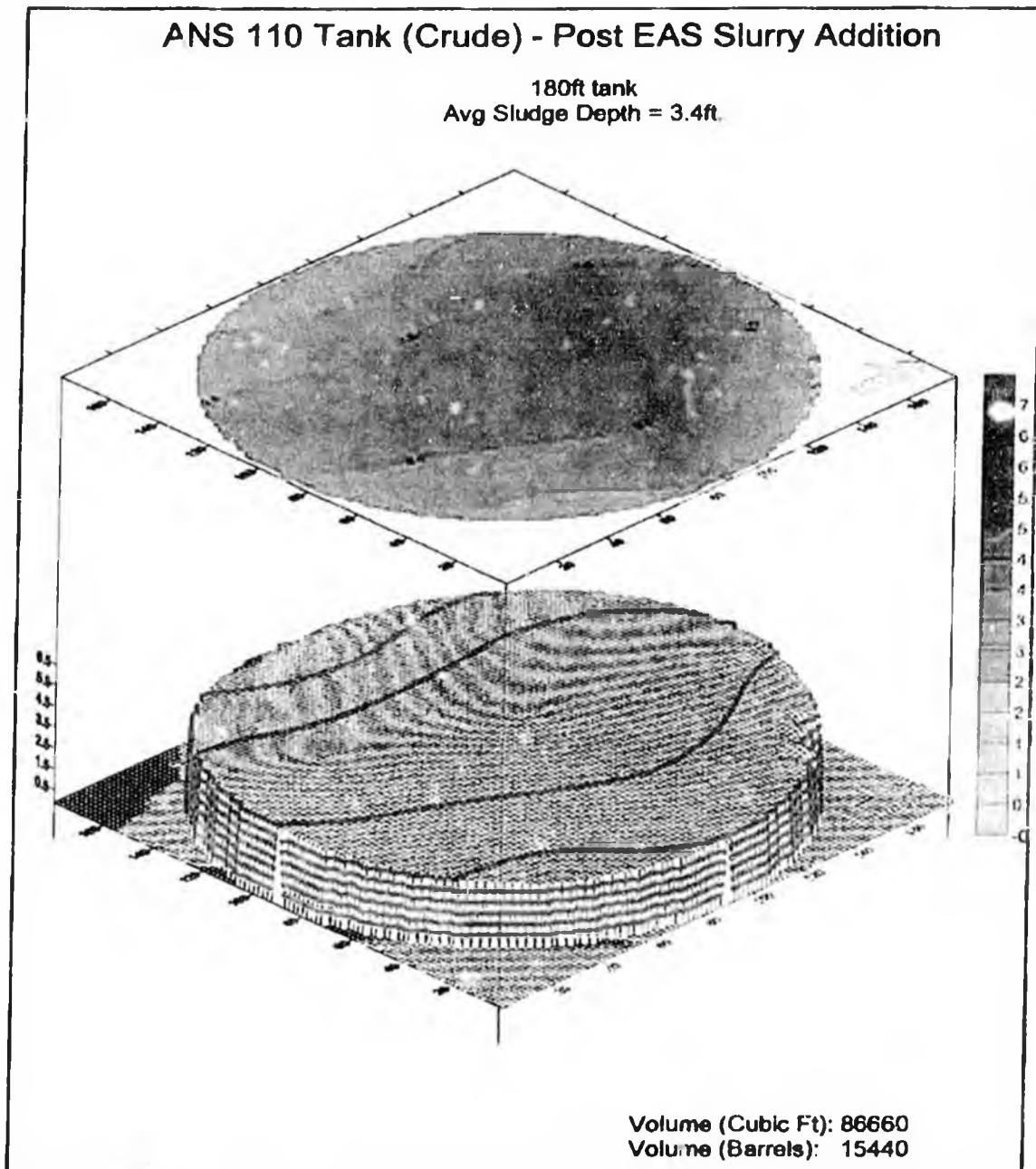
180ft tank
Avg Sludge Depth = 1.04ft.



Volume (Cubic Ft): 26580
Volume (Barrels): 4730

TK-110 Thermographic / 3-D Fluid Dynamic Modeling
Tank Bottoms Profile after EOA Piping Slurry Transferred to TK-110

Tank bottoms level rose significantly after introduction of EOA Slurry into TK-110. The bottoms volume increase was 10,710 BBL as compared to the original "hardpan" value prior to the project.

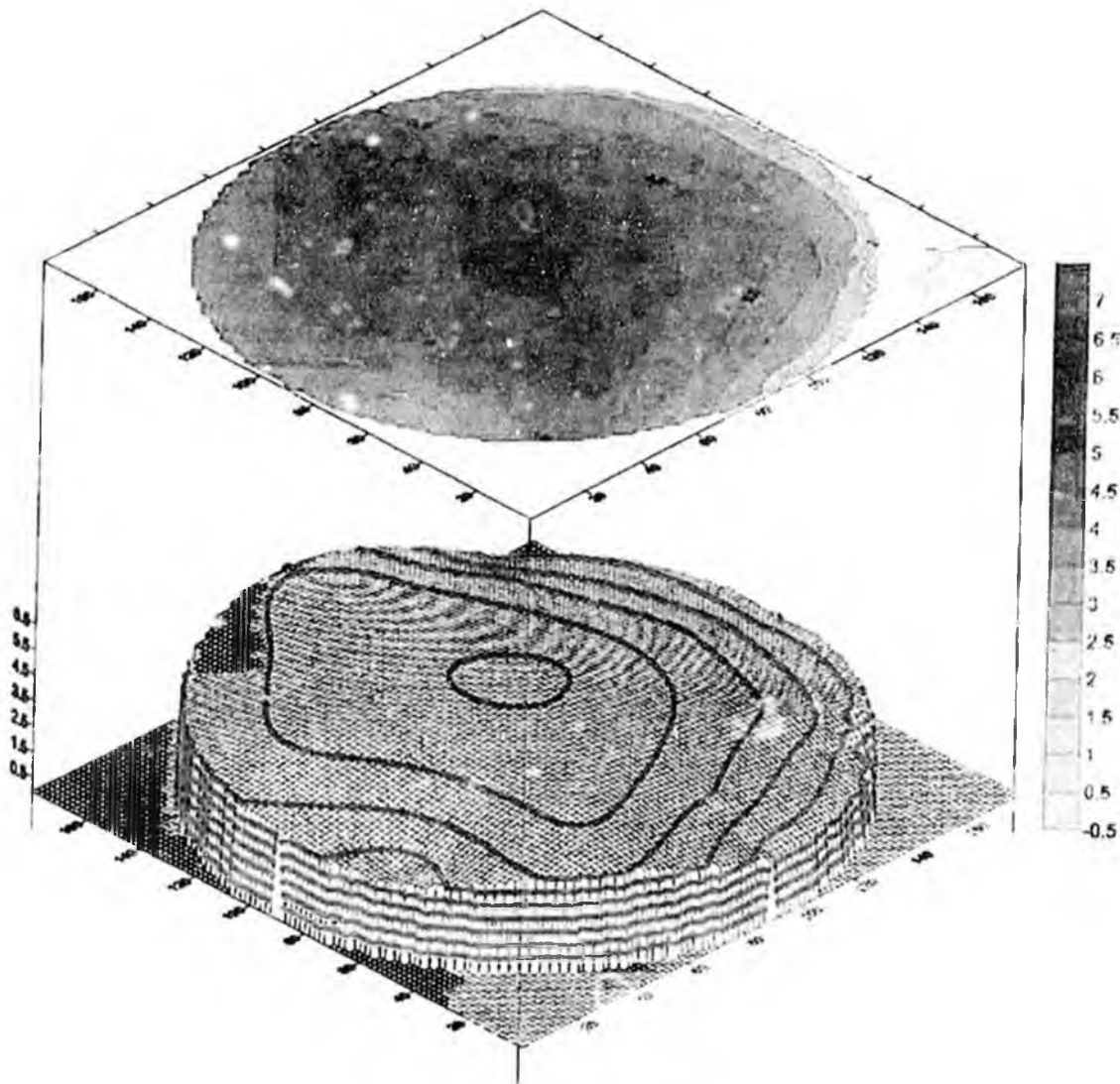


TK-110 Thermographic / 3-D Fluid Dynamic Modeling
Tank Bottoms Profile after WOA Pigging Slurry Transferred to TK-110

Tank bottoms level rise due to WOA was much less than EOA; as was expected. The incremental volume of tank bottoms added was 1010 BBL bring the total pigging solids accumulation to 11,720 BBL

ANS 110 Tank (Crude) - Pre Jet M^oring

180ft tank
Avg Sludge Depth = 3.62ft.



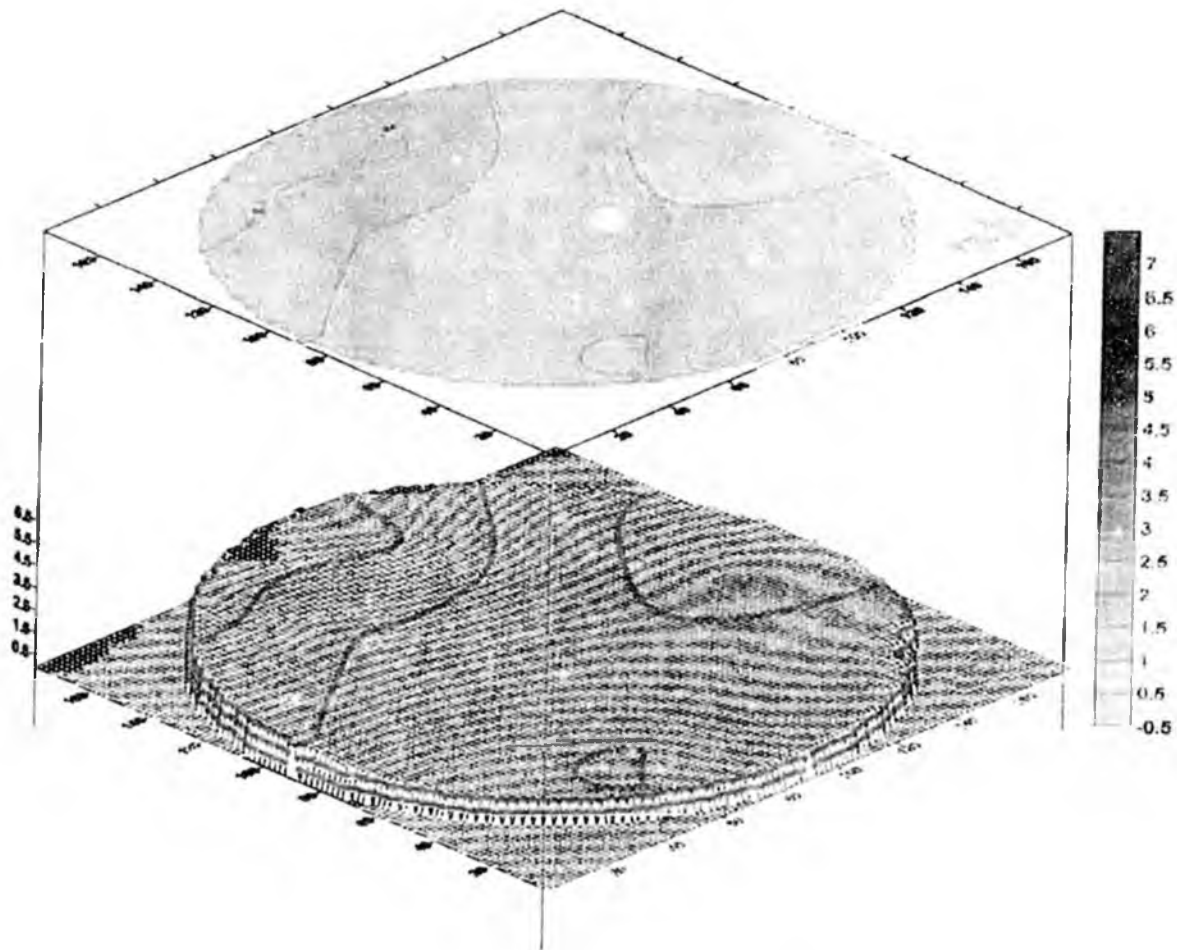
Volume (Cubic Ft): 92340
Volume (Barrels): 16450

TK-110 Thermographic / 3-D Fluid Dynamic Modeling
Tank Bottoms Profile after Higher Temperature Jet Mixing in TK-110

- A series of jet mixing strategies were employed to suspend the waxy tank bottoms in temperatures as low as 40's and as high as 90°F. The jet mixing liberated entrained solids and water and produced sheared wax molecules which dissolved into the crude and were decanted to TAPS.
- A total of 10,620 BBL of waxy tank bottoms were removed or 91% of the tank bottoms introduced via pigging.

ANS 110 Tank (Crude) - Post Jet Mixing Dec 4/2006

180ft tank
Avg Sludge Depth = 1.28ft.



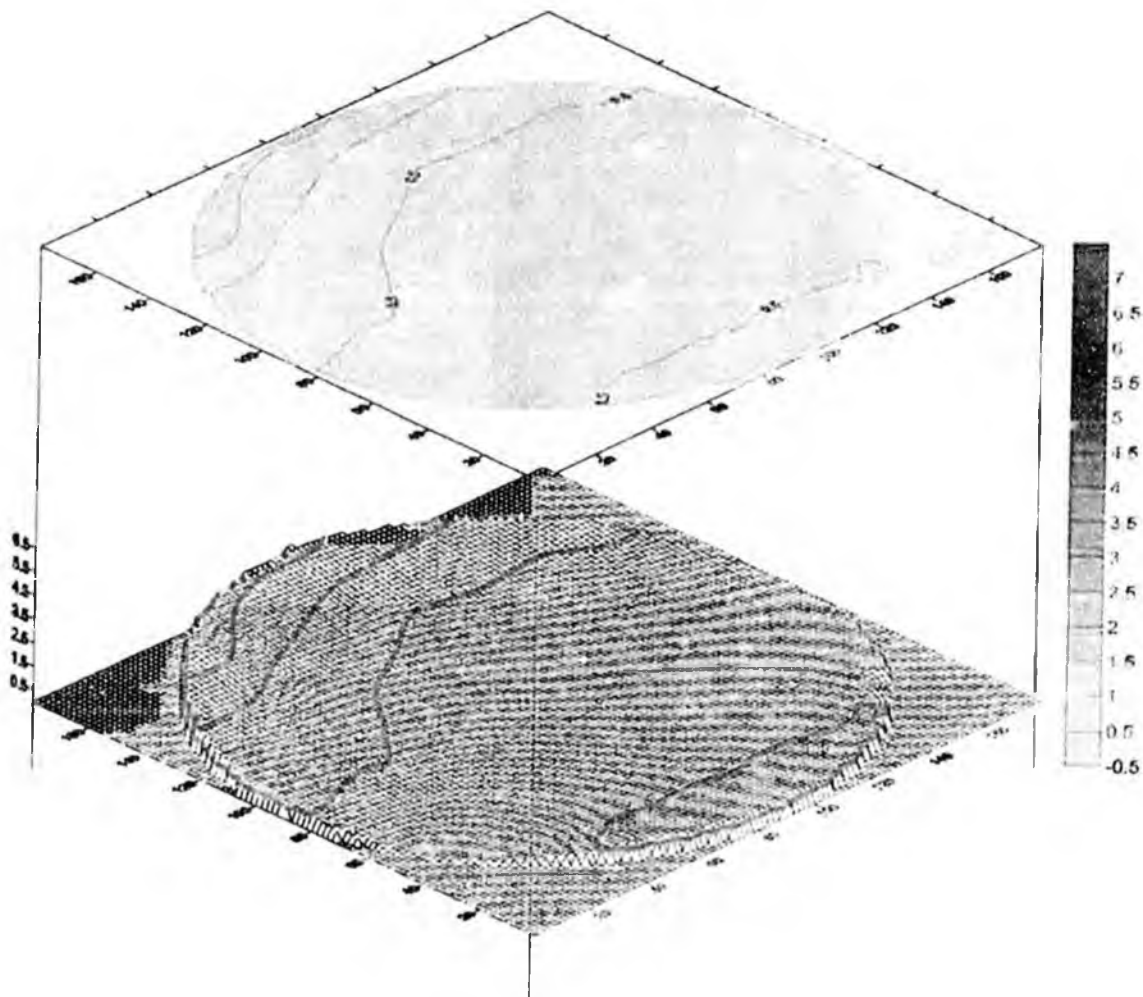
Volume (Cubic Ft): 32720
Volume (Barrels): 5830

TK-110 Thermographic / 3-D Fluid Dynamic Modeling
Tank Bottoms Profile after Lower Temperature Jet Mixing in TK-110

- Additional jet mixing was carried out after the introduction of hot crude (112°F+) which raised the bulk temperature of the jet mix slurry to over 95°F
- A total of 13,160 BBL of waxy tank bottoms have been removed. All of the pigging solids wax and 50% of the hardpan wax in the tank prior to the BPXA project was shown to be sheered and dissolved in the hot crude introduced to TK-110.

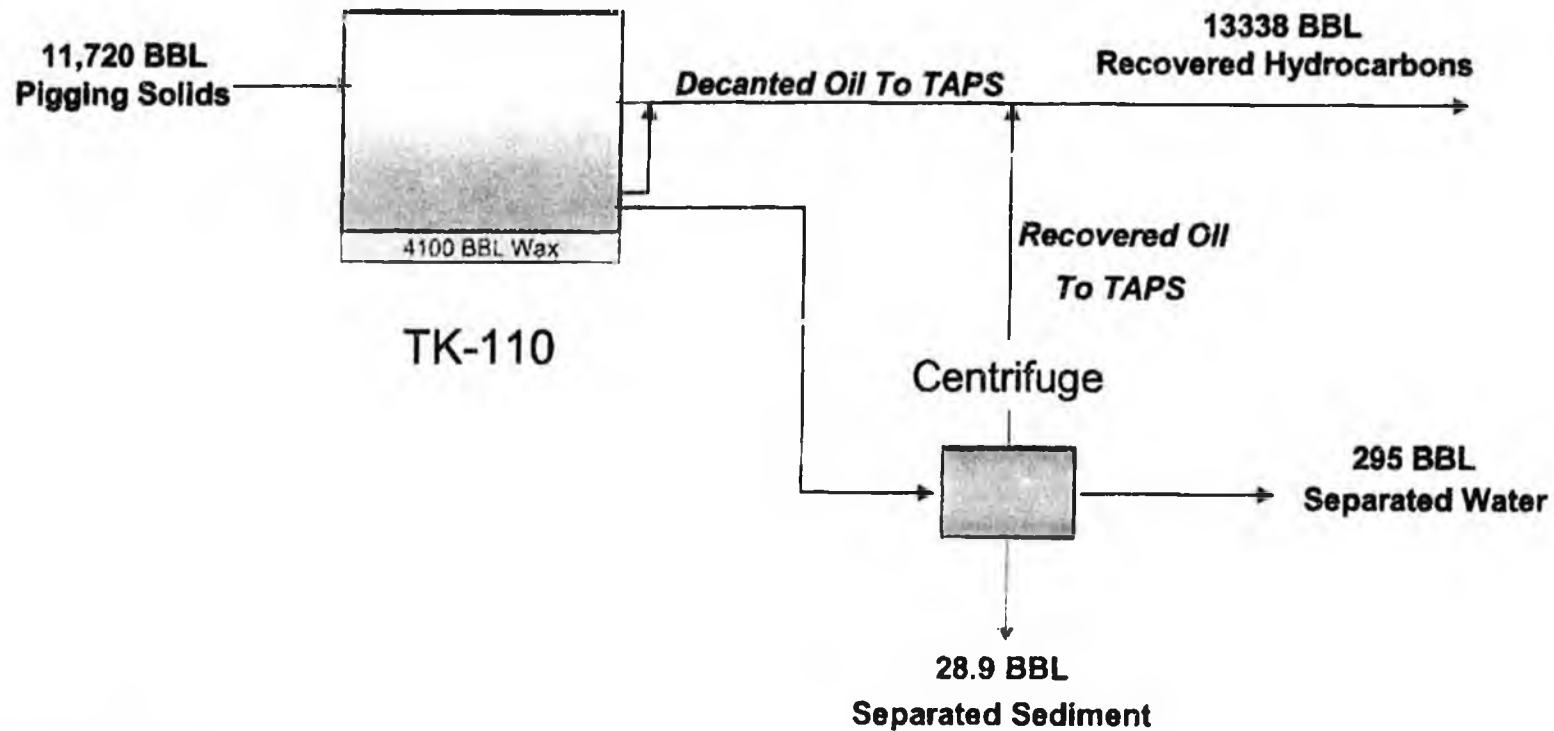
ANS 110 Tank (Crude) - Post Jet Mixing (12-12-06 4 PM)

180ft tank
Avg Sludge Depth = 0.5ft.



Volume (Cubic Ft): 12800
Volume (Barrels): 2280

BPXA – Pigging Solids Processing Thermographic Material Balance



Summary:

- BPX Pigging Solids consisted primarily of wax
- Prior to receipt of pigging solids, TK-110 had about 4100 BBL of wax on bottom
- Upon receipt the pigging solids settled to the bottom as an additional 11,720 BBL of waxy solids
- A tank bottom profile indicated 295 BBL of water and 31.6 BBL of sediment in the waxy bottoms
- Jet mix sheering and hot crude addition enabled all of the pig wax to be dissolved
- Processing skid recovered all of the water in the heavy bottoms and 92% of the sediment

Exhibit

4

bp



Doug Suttles

President

February 15, 2007

BP Exploration (Alaska) Inc.
PO Box 196012
900 E. Benson Boulevard
Anchorage, Alaska 99519-6012

Honorable Members
Alaska State Legislature
State Capitol
Juneau, AK 99801

Dear Ladies and Gentlemen:

A number of questions have been raised about BP's intent to deduct certain costs related to the Prudhoe Bay field shutdown last August. I am writing to confirm our position on this issue and at the same time reiterate BP's commitment to and plans for our business in Alaska.

Direct: 907 564 5422
Main: 907 561 5111
Fax: 907 564 5900
doug.suttles@bp.com

With respect to the deductibility of costs, we can only speak for BP. Taxes are paid on a company wide basis rather than a field specific basis and BP cannot speak for the other Prudhoe Bay owners on tax issues.

BP follows the law when it files its taxes. Accordingly, BP will assume the appropriate deductions & credits for the costs associated with the repair and replacement of the Prudhoe Bay Oil Transit Lines (OTLs). Specifically, BP will deduct appropriate costs associated with repair of the OTLs and will seek authorized credits for capital costs to replace them. Similarly in compliance with the PPT Laws, we will not seek to deduct costs associated with cleaning up the oil spills.

To put this issue into context, I would like to openly share our estimated 2006 production taxes.* For the final nine months of 2006, the period over which PPT was applicable, we estimate that BP's production taxes will almost triple from \$180 million under the old ELF-based tax to more than \$500 million under PPT. Over the same period, BP's share of the deductions and credits associated with the costs of inspection, business resumption, and replacement of the OTLs will result in a total deduction of around \$11 million in 2006, which we have included in our 2006 production tax estimate.

We believe our approach is appropriate for the following reasons:

- 1) It is important to realize that the OTLs are some 30 years old and were sized for significantly higher production than we will have in the future. The OTLs would have been replaced in the normal course of business, even if the events of last year had not taken place.
- 2) We are in the process of building a new state of the art pipeline system for the future life of Prudhoe Bay. This is not a like-for-like replacement. Rather, we are investing in a brand new system, with pipe diameter sizes very different than the original design to reflect the reduced production from these maturing oilfields. The new system will have new chemical injection systems, upgraded pig launchers/receivers, upgraded leak detection system, and a Fusion Bond Epoxy external coating for longer life. The system will be in operation for decades to come. We believe this investment is in the best interests of the State of Alaska and the North Slope producers.

We appreciate the opportunity yesterday to discuss our Alaska business with the Senate Resources Committee and update them on the commitments we made in August 2006.

BPXA-LEGIS00044

February 15, 2007
Page 2 of 2

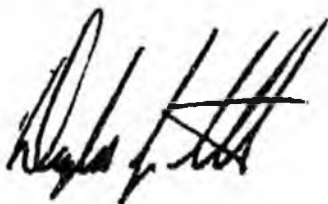
BP remains fully committed to the ongoing integrity of its facilities. As we embark on a vision of our next 50 years in Alaska, we will continue to make significant investment in facility renewal. This is not about replacement. It is about designing and constructing new facilities in a way that underpins the future and ensures the operability of the North Slope for decades to come.

With respect to PPT, last year the Legislature held long and difficult debates that ultimately led to the passage of PPT. The regulations are still being formalized as this legislation has not been in place for very long. We are only just preparing to submit our first tax returns under this new system. As a result, we believe it is premature to consider changes to the structure or intent of the current legislation. We believe it would be prudent for all parties, including producers and the State, to wait until PPT is fully implemented and we have real experience of its operation and impact before making any changes.

I hope I have provided you with the clarity of BP's intentions that many of you have been seeking and the reasoning behind the decisions we have made.

I look forward to working with the legislature as we progress our vision for our business in Alaska, including the commercialization of Alaska Gas, and as we bring our vision of a 50-year future to reality.

Sincerely,

A handwritten signature in black ink, appearing to read "Doug Suttles", with a stylized flourish at the end.

Doug Suttles

- Please note that, in disclosing in this letter certain specific tax information and BP's tax positions regarding PPT, BP does not intend to waive the confidentiality of any of its tax materials and information under applicable law (including AS 43.05.230), other than the particular information disclosed.

Debra Higgins

From: Cody Rice
Sent: Tuesday, May 22, 2007 10:54 AM
To: Rep. Scott Kawasaki; Rep. Bob Roses; Rep. Peggy Wilson; Rep. Craig Johnson; Rep. Carl Gatto;
Rep. Paul Seaton; Rep. Vic Kohring; Rep. Bryce Edgmon; Rep. David Guttenberg
Cc: Graham Siebe; Crystal Novotney; Debra Higgins; Louie Flora; Adam Berg; Daniel Consenstein
Subject: (H) RES Interim Meetings

Rep. Gatto would like to have two committee meetings in Anchorage next month on the topic of TAPS tariffs and oil pipeline integrity and safety.

We have a choice of four days: June 9th, 10th, 16th, and 17th. Each is a weekend to allow for easier travel and public participation. Please rank your choices from 1-4 with 1 being the best choice. If the day will not work for any reason please let me know ASAP.

Thanks for your help and participation.

Cody

Cody Rice
Staff to Rep. Carl Gatto
Telephone Number: 907-376-3725
Fax Number: 907-376-4768
<http://www.akrepublicans.org/gatto/index.php>

Brena, Bell & Clarkson, P.C.

**Presentation
to
House Resources Committee**

**Overview of TAPS Rate Litigation and FERC
Judge Cintron's May 17, 2007, Initial Decision**

June 7, 2007

Overview

- **Alaska's Oil and Gas Resources are Transported Through Pipelines with No Competition.**
- **Economic Regulation of These Noncompetitive Pipelines Must Meet Two Basic Goals:**
 - (1) Fair access, and
 - (2) Just and reasonable rates.
- **Meeting These Goals will Optimize:**
 - (1) The development of our oil and gas resources,
 - (2) Royalty and severance taxes, and
 - (3) Value-added manufacturing and jobs in Alaska.

The TAPS Settlement

- **TAPS Settlement:** In 1985, the TAPS Carriers and the State of Alaska settled prior rate issues and agreed that the State would not protest future rates as unjust and unreasonable so long as those rate filings were at or below the ceiling rates established under the TAPS Settlement Method ("TSM").
- **Request to Review TAPS Settlement Under "Public Interest" Standard:** The TAPS Carriers and the State asked the FERC and the RCA to review the TAPS Settlement under the "public interest" standard and not to review it under the "just and reasonable" rate standard.
- **Representation that Shippers Could Protest Future TSM Rates:** The TAPS Carriers and the State represented to the FERC and the RCA that if their TAPS Settlement was approved, any third-party shipper could protest future TSM ceiling rates as unjust and unreasonable and have the FERC or the RCA set just and reasonable rates.
- **Establishing Just and Reasonable Rates Does Not Violate the TAPS Settlement:** No party has requested the premature termination of the TAPS Settlement. The rate litigation before the FERC and the RCA is consistent with, and does not contradict, any term of the TAPS Settlement. The TAPS Carriers and the State continue to receive every benefit under the TAPS Settlement. The State still enjoys rates at or less than the TSM ceiling rates. The TAPS Carriers still enjoy the resolution of all prior rate issues and not having the State protest their TSM rates as unjust and unreasonable.

Rate Methods for TAPS

- **TAPS Settlement Method (“TSM”)**
 - Settlement method for ceiling rates only.
 - Rejected by the RCA, the Superior Court of Alaska, and Judge Cintron for establishing just and reasonable rates.
- **Stand Alone Cost (“SAC”) Method**
 - Based on hypothetical costs of new pipeline.
 - Rejected by Judge Cintron for establishing just and reasonable rates.
- **Original Cost Rate Methods**
 - Depreciated Original Cost (“DOC”) Method. RCA applied to TAPS for establishing just and reasonable rates in RCA Order P-97-4(151).
 - Trended Original Cost (“TOC”) Method. FERC adopted for all oil pipelines, with some modification, through FERC Opinion 154-B. Judge Cintron applied to TAPS in Initial Decision.

RCA Rate Proceedings

- **Major Claims:**

- In 1937, Tesoro claimed the state rates were unjust and unreasonable and asked the RCA to establish rates based on the DOC method.
- The TAPS Carriers and the State of Alaska defended the state rates and asked the RCA to continue to charge TSM rates.

- **RCA Decision:**

- In Order P-97-4(151), the RCA rejected the use of the TSM and established rates based on the DOC method. The state rate today is \$1.96 for all carriers.

- **Procedural Status of RCA Decision:**

- In January 2006, Superior Court Judge Suddock “affirmed the decision of the RCA in all respects.”
- The TAPS Carriers appealed to the Supreme Court of Alaska. The case has been argued before the Supreme Court and is awaiting decision.

FERC Rate Proceedings

- **Major Claims:**

- In 2005, Anadarko/Tesoro claimed the federal rates ranging from \$3.78 to \$4.41 (2006) were unjust and unreasonable and asked the FERC to establish a \$2.04 (2006) federal rate based on Opinion 154-B.
- The State of Alaska claimed the federal rates were discriminatory because they were higher than the state rate and asked the FERC to lower the federal rates.
- The TAPS Carriers claimed the state rate was noncompensatory and a burden on interstate commerce and asked the FERC to raise the state rate.

- **Judge Cintron's Initial Decision:**

- Established a \$2.04 (2006) federal rate based on Opinion 154-B.
- Dismissed the State of Alaska's claims as moot.
- Dismissed the TAPS Carriers' claims as moot.

- **Procedural Status of Initial Decision:**

- Appeal to FERC
- Appeal to the D.C. Circuit

Summary of Initial Decision

- **TSM:**
 - The TAPS Carriers failed to provide cost support for the TSM rate elements, so the TSM rates could not be found to be just and reasonable.
- **Opinion 154-B:**
 - Opinion 154-B must be used to establish just and reasonable rates;
 - Opinion 154-B does not permit the Carriers to double recover their investment, deferred earnings, AFUDC, or ADIT;
 - The Carriers are not entitled to a starting rate base write up;
 - Return must be based on a representative proxy group without a risk premium; and
 - Anadarko/Tesoro's Opinion 154-B calculation was adopted.
- **DR&R:**
 - Collections and earnings must be accounted for; and
 - Overcollections may be refunded.
- **Uniform Rate**
- **State of Alaska's Discrimination Claims:**
 - Dismissed as moot
- **TAPS Carriers' Section 13(4) Claims:**
 - Dismissed as moot.
- **Remedies:**
 - Refunds of rate increases for 2005 and 2006.
 - Cost-based Opinion 154-B rates going forward.

Just and Reasonable Rates

- **Just and reasonable rates are generally rates based upon the costs of providing service.**
- **Just and reasonable rates permit the Carrier an opportunity to recover:**
 - (1) Operating costs,
 - (2) Investment, and
 - (3) A reasonable return on remaining unrecovered investment.

TSM Rates Are Not Just and Reasonable

- **EXCESSIVE COLLECTIONS:** From 1977 through 2004, the TSM has resulted in \$18 billion in overcollections under the DOC method. During this period, the TAPS Carriers have invested \$10 billion in capital to build TAPS and \$15 billion to operate TAPS, but have collected \$60 billion in rates.
- **THE TSM IS FATALLY FLAWED:**
 - Allowance Per Barrel
 - Rates Are Based on Subjective Projections
 - Depreciation Based on the Wrong Economic Life
 - True-up of Total Revenue
 - Faulty Jurisdictional Separations
- **IMPACT TO STATE:** The TSM has cost the State of Alaska \$4.5 billion in royalty and severance taxes (\$18 billion * 25 percent) plus earnings.

TSM Rates Filed by TAPS Carriers

<u>Carrier</u>	<u>Rates</u>			
	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>
BP Pipelines (Alaska) Inc.	\$3.01	\$3.86	\$4.08	\$5.10
ConocoPhillips Transportation Alaska, Inc.	\$3.09	\$3.52	\$3.78	\$5.29
ExxonMobil Pipeline Company	\$3.07	\$3.60	\$3.93	\$4.95
Koch Alaska Pipeline Company, LLC	N/A	\$3.97	\$4.41	\$4.75
Unocal Pipeline Company	\$3.00	\$3.59	\$3.92	\$4.63

**Comparison of
Anadarko/Tesoro's 154-B and TAPS Carriers' 154-B
Total 2006 Revenue Requirements and Rates
(\$Millions)**

Line No.	Description	A/T 154-B	TAPS Carriers' 154-B
1	Operating Expenses	\$559.65	\$559.65
2	Depreciation Expense	\$13.48	\$335.43
3	Amortization of Deferred Earnings	\$7.13	\$223.84
4	Amortization of AFUDC	\$0.86	\$11.63
5	DR&R Allowance	\$0.00	\$0.00
6	Return Allowance		
7	Return on Equity	\$30.58	\$281.62
8	Interest	<u>\$13.77</u>	<u>\$9.59</u>
9	Total Return Allowance	\$44.34	\$291.21
10	Income Tax Allowance	\$22.13	\$329.04
11	Non-Transportation Revenues	(\$0.27)	<u>(\$0.38)</u>
12	Total Revenue Requirement	<u>\$647.32</u>	<u>\$1,751.18</u>
13	Composite System Barrels (Millions)	326.795	326.795
14	Composite Rate (\$/Bbl)	\$1.98	\$5.36
15	Valdez Interstate Rate (\$/Bbl)	\$2.04	\$5.53

**Differences Between
TAPS Carriers' 2006 154-B Proxy Revenue Requirement and Rate and
Anadarko/Tesoro's 154-B Revenue Requirement and Rate
(\$Millions)**

	<u>Revised Revenues</u>	<u>Revised Rate</u>
TAPS Carriers' 154-B	\$1,751.18	\$5.36
Less Revenue from Deferred Earnings	(\$580.60)	(\$1.78)
Less Revenue from Starting Rate Base	(\$95.02)	(\$0.29)
Less Revenue from Accelerated Portion of Depreciation and Other	<u>(\$428.23)</u>	<u>(\$1.31)</u>
Anadarko/Tesoro's 154-B	\$647.32	\$1.98

Dismantlement, Removal & Restoration ("DR&R")

- DR&R is the cost of taking a pipeline out of service at the end of its economic life.
- A pipeline carrier is entitled to collect DR&R from its shippers. DR&R should be a zero-sum game for the carrier.
- The TAPS Carriers have collected \$1.5 billion for DR&R from 1977 to date. They have had the unrestricted use of these shipper funds for decades and have actually earned approximately \$15.7 billion on those funds through 2005. The TAPS Carriers have said they only need \$2.6 billion (2005) for DR&R.

History of the State of Alaska's Pipeline Positions

- **Out Resourced**
 - Out litigated
 - Out negotiated
 - Out staffed
- **Limited Successes**
 - Never established a just and reasonable rate
- **Bad Settlements**
 - Negotiating away the basic right to ensure the settlement remains fair
 - TAPS Settlement
 - Feeder lines to TAPS (Depreciation/DR&R)
 - Murkowski Gas Line Agreement
 - CIPL
- **Restrictive Interpretation of Duty to Defend in the TAPS Settlement**
 - Forecloses the State from protesting TSM ceiling rates as unjust and unreasonable
 - Does not foreclose the State from clarifying that shippers have the right to request just and reasonable rates (TAPS Carriers' misrepresentations concerning the TAPS Settlement)
 - Does not foreclose the State from litigating issues not settled in the TAPS Settlement (DR&R)
 - Does not require the State to continue to litigate against shippers trying to get just and reasonable state rates (P-97-4, P-86-2)
- **No Clear and Consistent Policy or Client**
 - No clear policy concerning access
 - No clear policy concerning just and reasonable rates
 - No clear client. AS 42.06.140(a)(10) Attorney General—Attorney and Client

State of Alaska's Financial Stake

- 25 Percent of Refunds and Interest for 2005 and 2006.
- 25 Percent of Lower Refunds and/or Interest for 2007 Forward.
 - DOR Understates Benefit to State by Assuming Benefit Ends in 2008.
 - Example: \$211.7 Million for 2007
[(\$4.94 - \$2.04) * 800,000 BPD] * 365 * 25%
- 25 Percent of DR&R Refunds

Lessons for the Gas Line

- Don't Leave Anything to the FERC
- Resource the Effort
- Get Gas for Alaskans
- Get Access Right
- Get Rates Right
- Have a Very Good Reason If You Decide to Give Control of the Line to a Few Major Producers (Alignment)
 - Impact on Access
 - Impact on Rates
 - Impact on State of Alaska's Power to Manage and Tax its Own Resources

Additional Materials

- **RCA's Order 151:**

Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues (11/27/02)

http://www.state.ak.us/rca/orders/pipeline/1997/p97004_151.pdf

- **Judge Suddock's Decision Affirming Order 151:**

Decision and Order (01/19/06)

[http://rca.alaska.gov/data/docketDetail.html?docket=P-97-004A\(1\) at 012020060858327](http://rca.alaska.gov/data/docketDetail.html?docket=P-97-004A(1) at 012020060858327)

- **Judge Cintron's Decision:**

Initial Decision (05/17/07)

http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20070522-0215

- **Errata to Judge Cintron's Decision:**

Errata to Initial Decision (05/31/07)

http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20070531-3066

From the desk of

Richard A. Fineberg

P.O. Box 416, Ester, Alaska 99725

Phone / Fax (907) 479-7778 E-mail: fineberg@alaska.net

To: Members of the House Resources Committee

Date: June 7, 2007

Re: Questions for Department of Law on TAPS Tariffs
(For Committee Members Only)

Here are 20 Questions for the Alaska Department of Law on TAPS Tariff and Tariff Management Issues. Additional information on each of these questions can be found in my prepared testimony for today's hearing (and on my web site).

I. Fiscal Impacts of TAPS Tariff Challenges on State Revenue

1. Fiscal Outcomes of Current Tariff Challenges.

- A. Please identify the factors that account for the change in the Department of Revenue's latest refund estimates.
- B. When did the Department of Law ask the Department of Revenue to quantify the impacts of the CY 2005 and CY 2006 tariff protests?
- C. When tariffs for CY 2008 will not be filed until December 2007, how was the CY 2008 estimate derived?
- D. When actual tariff data exists for CY 2005 through CY 2007 but future tariff data are not yet available, was it appropriate to include CY 2008 estimates with the three prior years?
- E. Did the Department of Revenue estimate revenue lost, based on the difference between the RCA tariff and the FERC tariff, for CY 2003 and CY 2004, or the full amount of the difference between a timely filing of a TOC tariff and the actual filed TSM?
- F. Why did estimates of future impacts terminate with CY 2008?

2. State CY 2004 TAPS Tariff Overcharge Protest at FERC.

- A. Please indicate the status or disposition of each of the alleged TAPS tariff overcharges in the State's CY 2004 TAPS Tariff Protest.
- B. Please indicate the estimated amount of the state revenue that was potentially at issue for 2004 and specify whether those amounts were included in the figures presented in response to Question 1, above.

3. State CY 2005 and CY 2006 TAPS Tariff Overcharge Protests at FERC.

- A. Is the State still seeking recovery of revenue lost due to alleged CY 2005 and CY 2006 tariff overcharges by the TAPS Carriers?
- B. If not, how were the State's protests resolved?
- C. If so, please indicate the status of the challenge to each of those alleged TAPS tariff overcharges.

- D. Please indicate the estimated amount of the state revenue that was potentially at issue for 2005 and 2006 and specify whether those amounts were included the figures presented in response to Question 1, above.

4. Fiscal Outcomes of Tariff Protests Since 1996.

- A. Please provide estimates of the annual amounts that might be obtained in refunds for tariff items the State has protested during this period as inconsistent with TSM terms.
- B. Please provide comparable estimates of the annual amounts that might have been obtained in refunds for tariff overcharges such as those alleged by Anadarko and Tesoro under the statutory standard of a "just and reasonable" tariff under AS 42.06 or comparable federal statute.

5. Tariffs below TAPS Settlement Agreement Ceiling (Re: 1997 Capacity Settlement Agreement)

- A. For oil shipped under FERC tariffs since Jan. 1, 1998, please provide, by year, the average amount per-barrel by which the annual TAPS Settlement Agreement ceiling has exceeded actual TAPS tariffs under FERC jurisdiction.
- B. Have the Department of Law and/or its consultants analyzed the 1997 Capacity Settlement Agreement to determine whether excess capacity naturally occurring on TAPS due to reduced throughput would have resulted in (a) the filed below-ceiling tariffs on TAPS and/or (b) additional tariff reductions?
- C. If so, can you provide those analyses?

II. State Position in Current FERC Proceedings

6. Tariff Levels.

- A. How does the State reconcile its present support of the relatively low TAPS tariff levels it opposed for nearly two decades, and as recently as 2004?
- B. How does the State reconcile its present support of the relatively low TAPS tariff levels it opposed as recently as 2004 with its previous assertions to FERC that the much higher tariffs filed under the 1985 TAPS Settlement Agreement were both "cost-based" and "fair and reasonable"?

7. Depreciation.

- A. How did the Department of Law and its consultants arrive at the decision to reverse its long-held position that no element of the 1985 settlement can be viewed outside the context of the settlement because TSM is the product of a negotiated settlement involving many inter-related compromises and tradeoffs?
- B. Could a better explanation for this switch in a long-held position have enhanced the State's credibility in this proceeding?
- C. Why did it take the Department of Law and its consultants 20 years to recognize that the Carriers' tariff filings under TSM were double-counting depreciation expenses to overcharge independent shippers?

8. Per-Barrel Allowance.

- A. Have the Department of Law and its consultants compared the amounts the TAPS Carriers have gained through tariff collections realized through the inflation-adjusted per-barrel allowance in effect under TSM since 1990, plus other profit elements, to an allowable standard rate of return profits on a depreciated rate base under a standard cost-based ratemaking method?

9. May 17, 2007 FERC Administrative Law Judge Decision.

- A. Please identify the specific items in the ALJ decision in which the State believes it achieved significant victories.
- B. For each point on which the State believed it achieved significant gains, please provide a statement of the fiscal impact of each item and/or a brief summary of the policy implications of that item.

III. Independent Producers and Shippers

9. The State and Independent Producers/Shippers.

- A. How do the Department of Law and its consultants reconcile the State's prolonged opposition to independent shipper challenges to excessive TAPS tariffs with its assertions (e.g., in the Explanatory Statement accompanying the submission of the 1985 settlement agreement to FERC) that Alaska stands in the shoes of the shippers?
- B. Does the prolonged levy of excessive TAPS tariffs handicap independent producers, who must pay the excess tariffs out of pocket?
- C. Does the prolonged levy of excessive TAPS tariffs have a chilling effect on North Slope exploration and development by companies other than the TAPS owners?

10. Excess Tariff Handicaps to Independent Shippers.

- A. When a TAPS Owner ships its own oil, tariff charges in excess of actual costs represent internal transfer payments between the production and the transportation arms of the company. In contrast, the independent shipper must pay these costs out of pocket. Has the Department of Law asked its consultants or the Department of Revenue to quantify the handicap to independent shippers on TAPS of excess charges under the TAPS Settlement Methodology?
- B. If so, please provide that information on an aggregate and a per-barrel basis.
- C. Compared to TAPS tariffs filed under the 1985 settlement methodology, correction of these four specific tariff elements in the filed 2006 tariffs would reduce TAPS tariff revenue by approximately 60% (from more than \$5.00 per barrel to approximately \$2.00 per barrel). By comparison, if the State prevailed in its protest of specific elements of the 2006 tariff, what would the reduction to TAPS tariffs have been on an aggregate and a per-barrel basis?
- D. For CY 2003, 2004 and 2005, following the A/T methodology please provide the amounts of corrections to the four specific tariff elements discussed in this question on an aggregate and per-barrel basis.

- E. By comparison, For CY 2003, 2004 and 2005, if the State were successful in its protest of specific tariff elements, what would the reduction to TAPS tariffs have been on an aggregate and a per-barrel basis?

11. Antitrust Issues.

- A. When did the Department of Law become aware of Conoco CEO Archie Dunham's statement that he hated to give up the Milne Point field, but "all the value of that property was taken away in the pipeline tariffs;" what action did the department take to determine whether there was a relationship between pipeline tariffs and the departure from Alaska of the only independent operator on the North Slope?
- B. When did the Department of Law become aware of the Maritime Endeavor case and what action did the Department of Law take to determine whether the company's complaint had merit?
- C. Are the Department of Law and its consultants aware of any other state or region producing more than 500,000 bpd in which (1) the only link to market is dependent on largely producer-owned transportation links whose average cost exceeds \$4.00 per barrel and/or (2) three or fewer producers own more than 95% of the only pipeline link to market and control a similar share of production?

IV. Duty to Cooperate in Defending 1985 TAPS Settlement Agreement

12. Duty to Cooperate in Defending the 1985 TAPS Settlement Agreement.

- A. Since the State evidently did not deem itself contractually bound to join the TAPS Carriers in actively defending the 1985 TAPS Settlement Agreement after Feb. 28, 2006, what factors prompted the State oppose the challenges of independent TAPS shippers at the RCA between 1996 and February 28, 2006, despite the fact that reduced tariffs would augment State revenue and promote competition on the North Slope by independent developers?

13. Definition of Duty to Cooperate in Defending the 1985 TAPS Settlement Agreement.

- A. Has the Department of Law attempted to determine the extent to which Sec. 1-3 of the 1985 TAPS Settlement Agreement constrains the State's current challenges to TAPS tariffs?
- B. Has the Department of Law ever attempted to determine the legal extent to which Sec. 1-3 of the 1985 settlement agreement constrained the State's challenges of possible or actual TAPS tariff overcharges between 1986 and the the present?
- C. If so, please (1) indicate the dates that written documents on this subject were prepared and (2) provide those documents.

V. TAPS Tariffs Under TSM v. Explanatory Statement Prognostications

14. Tariff Levels under TSM (1990-2011):

- A. What accounts for the radically differences between (a) the tariff outcomes calculated by the RCA and the FERC Trial Staff and Administrative Law Judge and (b) the prognostications of the 1985 *Explanatory Statement*?

- B. Please compare TAPS throughput from Jan. 1, 1986 through Dec. 31, 2006 to the forecast figures used in the Explanatory Statement prognostications?
- C. All other things being equal, in comparing actual results to 1985 projections, shouldn't increased production and reduced federal income tax rates have resulted in decreased tariffs, compared to 1985 projections?

15. Other Representations.

- A. In view of the facts that (a) tariffs under the 1985 settlement were significantly higher than a standard DOC tariff would have been and (b) the RCA, FERC Trial Staff and FERC Administrative Law Judge concur that actual tariffs filed in compliance with the settlement agreement have been excessive, what is the basis for the prognostications of the 1985 *Explanatory Statement* and the 2001 statements of the Department of Law's counsel, on behalf of the State, to the RCA that the 1985 TAPS Settlement Agreement "has performed better than expected"?

16. Dismantling, Removal & Restoration (DR&R).

- A. What specific settlement benefits did the State receive from granting, through the 1985 settlement, DR&R collection terms to the TAPS owners that, according to the 1986 calculations of the APUC Staff Expert Witness, increased the estimated settlement gains to the TAPS Owners by more than 50 percent?
- B. In the two decades since this defect in the 1985 Settlement terms was identified and the resulting after-tax, off-book gains to the TAPS Owners were quantified, what steps did the Department of Law and its consultants take to remedy this situation?
- C. In 2000, the Department of Law became aware that a 1988 ruling by the U.S. Internal Revenue Service increased the tariff gains to TAPS Owners by making the DR&R pre-collections (which had been "grossed up" under the settlement terms to pay federal income tax) tax-deductible. At that time, the attorney representing the Department of Law promised the Legislature the attorneys and accountants would get to the bottom of this issue and remedy it. What substantive actions (if any) have the Department of Law and its consultants taken in the intervening six years to remedy this problem and what is the status of these efforts?

(VI.) Natural Gas Pipeline Tariffs

17. Sensitivity to Pipeline Tariffs.

- A. Has the State prepared estimates of project tariffs for a proposed natural gas line? If so: (1) What is the range of the tariff estimate per mmBTU? (2) Does the variation in estimates reflect (a) differences in project costs, (b) uncertainty about FERC inputs, treatment of costs and other factors critical to tariff methodology, or (c) both?
- B. Does the EconOne estimate of approximately \$1.50 per mmBTU, plus or minus 20%, incorporate uncertainty about FERC inputs, treatment of costs and other factors critical to tariff methodology?

- C. Does the State believe that natural gas trades at a discount to oil? If so, does that discount factor increase project sensitivity to tariffs?

18. Strategies to Reduce Sensitivity to Pipeline Tariffs.

- A. Have State tariff managers presented a strategy (with timelines for data submission and analysis, agency and court review procedures) that will ensure that just and reasonable gas pipeline tariffs are established in a timely manner?
- B. On May 12, 2006, a Department of Law consultant representing the Administration assured legislators that, at least in theory, producers could be expected to contain pipeline costs to a greater extent than independent pipeline builders because, as shippers, they would have to pay the tariff. (1) Has the Department of Law explained the apparent contradiction between the historical reality of TAPS tariff charges and his statement?

(VII.) Pipeline Tariff Management Issues

19. Payments to Department of Law Consultants.

- A. It has been reported that between 1981 and June 30, 1997, the Department of Law paid Morrison & Foerster and its associates more than \$20 million for legal assistance associated with TAPS tariffs. Does this amount include payments to accountants working with Morrison & Foerster, including Dr. Thomas Horst?
- B. How much did the State of Alaska pay Morrison & Foerster and its associates, including Dr. Thomas Horst, for work on TAPS tariff issues between July 1, 1997 and June 30, 2003?
- C. According to the *Alaska Budget Report*, between July 2003 and the end of 2006 the State paid the law firm of Morrison & Foerster \$12.3 million for legal services and negotiations. Does this payment include payments for work on TAPS, including payments to Dr. Thomas Horst, for work on TAPS tariff issues?
- D. Between July 2003 and the end of 2006, how much did the State of Alaska pay Morrison & Foerster and its associate accountants, including Dr. Thomas Horst, for work on TAPS tariff issues?

20. Responsibility for State Pipeline Tariff Policy. *The Alaska Pipeline Act lists ten general powers and duties of the RCA under which that agency regulates pipelines and pipeline carriers in the state. The final subsection states that the commission*

(10) shall provide all reasonable assistance to the Department of Law in intervening in, offering evidence in, and participating in proceedings involving a pipeline carrier or affiliated interest and affecting the interests of the state, before an officer, department, board, commission, or court of another state or the United States.

- A. Apart from this statutory reference to the Department of Law, please identify any statutes that specifically assign responsibility for pipeline tariff policy to the Department of Law.

- B. The various sections of the Civil Division of the Department of Law handle legal matters and provide legal advice to the agencies of the executive branch. What state agency has statutory authority to set and review pipeline tariff policies?
 - C. Please identify any functions of State government for which the Civil Division of the Department of Law not only handles legal matters associated with implementing policy, but also has (1) statutory and/or (2) *de facto* responsibility for setting and reviewing that policy.
-

**Twenty Questions on Trans-Alaska Pipeline System Tariffs
And State Pipeline Tariff Management Issues**

Richard A. Fineberg
Research Associates
PO Box 416
Ester, AK 99725

Testimony before the Alaska State House of Representatives
Committee on Resources
June 7, 2007

Thank you for the opportunity to testify today on petroleum pipeline tariff issues. Pipeline transportation arrangements are critical to petroleum development. For this reason, I commend this committee for its initial effort to explore this important subject last March, and for your follow-up today. I am testifying today on my own behalf.

Mr. Chairman, it is no secret that I believe that responsibility for State petroleum tariff policy formulation rightly belongs with a line agency, such as the Department of Natural Resources. In most areas of State governance, the Department of Law serves a client agency by handling legal matters under the direction of that agency. But in the case of pipeline tariff management, that's not the way it works. I believe recent developments on TAPS and the proposed natural gas pipeline combine to confirm the importance of ensuring that clearly considered policy goals and directives are driving State actions in this important area.¹

In broad terms, the importance of TAPS tariffs to the State Treasury is outlined in an analysis I prepared in February 2007 for the *Alaska Budget Report* on fiscal impacts of the TAPS tariff cases before FERC and the State Supreme Court. Mr. Chairman, that report was by no means perfect. But to the best of my knowledge, at the time I prepared these estimates, those were the only comprehensive numbers out there. Strange as it may seem, despite the important effects of TAPS tariffs on State revenue and the time and energy the Legislature spent in 2006 looking at the petroleum revenue picture, the State had not published (and, I suspect, may not have performed) a comprehensive, quantitative assessment of potential TAPS tariff litigation effects on State revenue. I estimate that since I completed that report earlier this year, the State treasury has lost another \$55 million due to excess TAPS tariffs, based on the difference between FERC and RCA tariffs.²

I therefore commend you for your efforts today and encourage you to look very carefully at what has happened since you met in March to learn about a FERC document that excoriated the TAPS Owners' defense of their high filed TAPS tariffs.

¹ My comments are based on three decades of observation of North Slope petroleum development as a reporter, as a public servant (including six years on the inside as a policy analyst in the Governor's Office – three years working on budget and revenue issues and three years as a senior advisor to the Governor on oil and gas policy) and as a consultant.

² For background information on the basis of this estimate, see: Richard A. Fineberg, *Historical and Current State Revenue Loss Quantified: Difference Between RCA's 2002 TAPS Tariff Order And State's 1985 Pipeline Tariff Agreement Costs State More Than \$400 per Minute*, Feb. 28, 2007 (prepared for the Alaska Budget Report; on-line at <http://www.finebergresearch.com>).

At the March 5 hearing, Steve Brose, an attorney for the TAPS Owners, told you that the Feb. 16, 1007 FERC Trial Staff brief was just the view of one guy in Washington. That evidently wasn't the case. And Mr. Brose assured you that the TAPS Owners would be responding to the FERC Trial Staff brief "quite vigorously." Despite that defense, FERC Administrative Law Judge Carmen Citron's May 17 decision closely followed the arguments of the FERC Trial Staff and the TAPS Owners went down in flames. The judge recommended that the FERC reduce TAPS tariffs to levels near those ordered by the RCA. I'm not altogether surprised that the TAPS Owners declined to appear today.³

Since you last convened to consider this issue, attorneys for the TAPS Owners made another vigorous appearance in another venue: They appeared before the Alaska Supreme Court in Anchorage March 13 to appeal the challenge to the RCA's 2002 decision and order requiring the TAPS owners to reduce tariffs on in-state shipments to approximately \$1.96 per barrel.⁴ In my estimation, the TAPS Owners' appearance before the State Supreme Court was the latest example of their use of everything but the kitchen sink and meaningful ratemaking data to justify their unreasonably high tariffs. Here, too, their arguments were vigorous.

And no wonder: Whatever the TAPS Owners' odds of success before the State Supreme Court, a filed tariff in excess of just and reasonable rates enables the major TAPS Owner to retain hundreds of thousands of dollars per day that they would have to pay the State.⁵ As a practical matter, it is often – if not always – more difficult to collect refunds after the fact than to collect the right amount in the first place.⁶ Chalk up the lost refunds to another example of the price the State pays for its historical failure to respond with alacrity to the TAPS Carriers' high filed tariffs.

I believe the FERC decision is unusual in the remarkable degree to which Judge Cintron's decision lines up with the principal arguments of the FERC Trial Staff and the protesting shippers. For example, in setting out the methodology and in her findings and conclusions, the FERC judge adopted Anadarko and Tesoro's tariff numbers.⁷ I can't

³ Presiding Administrative Law Judge Carmen A. Cintron, "Initial Decision," in *BP Pipelines (Alaska) Inc., et al.* (FERC Docket No. IS05-82-002, etc.), May 17, 2007, *passim*.

⁴ See: Regulatory Commission of Alaska, *Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues* (Docket Nos. P-97-4 and P-97-7, Order P-97-4[151] / P-97-7[110]), Nov. 26, 2002 (I have discussed the significance of this order in various articles posted on my web site since I initiated that enterprise in September 2004.)

⁵ Two simple facts explain this problem: (1) For every dollar paid in tariffs, the State loses approximately \$0.25. (2) Three major oil companies own more than 95% of TAPS and control a roughly similar share of North Slope production. For a producer shipping its own oil, excess tariff payments are an internal transfer payment, not a cash outlay.

⁶ If Judge Cintron's Initial Decision stands, it appears that future tariffs will be lowered to approximately \$2.00 per barrel, but the State will not be able to collect full refunds on the difference between that level and higher filed past tariffs. Rather, the refunds she ordered for 2005 and 2006 will be based on the difference between the filed tariffs for CY 2004 and the filed CY 2005 and 2006 tariffs. ("Initial Decision," p. 106.)

Filed tariffs in CY 2004 averaged approximately \$3.11 – more than \$1.00 per barrel above what Judge Cintron's order sets as the just and reasonable tariff for TAPS shipments. (See: *Historical and Current State Revenue Loss Quantified: Difference Between RCA's 2002 TAPS Tariff Order And State's 1985 Pipeline Tariff Agreement Costs State More Than \$400 per Minute*, Figure 1, note 5.)

⁷ "Initial Decision," p. 40.

assess for you the odds that the FERC itself will uphold Judge Cintron's May 17 Initial Decision. But I can tell you this: Since Tesoro launched its protest of TAPS tariffs at the Alaska Public Utilities Commission (predecessor to the RCA) in 1996, the TAPS Owners have lost every major challenge to their high tariffs.⁸ In view of the foregoing, my guess – and my hope for the State – is this: At the end of the day, the Courts are likely to find that the law and the public interest lie with the protesting shippers.

Near the end of her May 17 decision, Judge Cintron devoted a few brief paragraphs to the State's primary argument in this proceeding. The State had argued that "[t]he State's protests of the TAPS Carriers' proposed 2005 and 2006 tariffs raise a single, simple question – can the TAPS Carriers charge vastly different rates for transportation of oil solely on the basis of where shippers take their oil after it leaves TAPS?"⁹ Judge Cintron's decision concluded that her findings on behalf of the shippers rendered the State's principal argument in this case moot.¹⁰ Judge Cintron also ordered that the

⁸ A quick summary of these decisions follows:

In its 2002 decision and subsequent orders on TAPS tariffs, the RCA upheld the protests of independent shippers that tariffs charged by the TAPS Owners were excessive. In doing so, the Commission rejected arguments by the State of Alaska and the TAPS Owners. In that proceeding, the State, represented by the Department of Law and its consultants, argued to the effect that TAPS tariffs filed under the 1985 TAPS Settlement Agreement serve Alaska public policy interests well and should remain in place.

The State joined the TAPS Carriers in appealing the RCA's 2002 decision; in January 2006, the Alaska Superior Court upheld the RCA decision "in all respects," rejecting the arguments of the Carriers and the State. The State subsequently withdrew from the TAPS Carriers' appeal to the State Supreme Court.

In December 2004, the State and independent shippers Anadarko and Tesoro (A/T) protested TAPS tariffs filed by the Carriers at FERC. The Department of Law has emphasized that the State's protest at FERC is based on different grounds from the protests brought by the independent shippers.

On Feb. 16, 2007, the various parties to the FERC proceeding filed their initial briefs with the FERC Administrative Law Judge, who is charged with the task of determining facts and laying out the principal arguments for the commission itself. Unlike the independent shippers, who argued that the filed tariffs were excessive, the State's principal argument was that the tariffs should be reduced because the different tariffs would be discriminatory and would therefore violate the Interstate Commerce Act. In the estimation of many observers the most notable brief was filed by the FERC Trial Staff, which supported the A/T position and rejected the arguments of the Carriers. The FERC Trial Staff took no position on the State's principal argument, arguing that a just and reasonable tariff at FERC would bring the FERC and RCA tariffs into line, removing the tariff differential the State argued would be discriminatory. The FERC Trial Staff also supported a single tariff on TAPS.

(For citations and additional discussion see: Richard A. Fineberg, *Alaska Department of Law Imitates Wrong-Way Corrigan: Famous Aviator Left New York For L.A., Landed in Ireland – With increasing recognition focusing on Trans-Alaska Pipeline System (TAPS) shipping costs, does the peculiar history of TAPS tariff ratemaking hold lessons for the proposed natural gas pipeline?* [March 2, 2007 web site comment.]

⁹ "Initial Post-Hearing Brief of the State of Alaska," in *BP Pipelines (Alaska) Inc., et al.* (FERC Docket No. IS05-82-002, etc.), Feb. 16, 2007, p. 11.

¹⁰ "Initial Decision," pp. 112-113. In her 277-paragraph decision, Judge Cintron dealt with the State's principal argument between paragraphs 258-263. In that section, she wrote:

It has been found in this initial decision that the TAPS interstate rates for 2005 and 2006 are unjust and unreasonable. Thus, this decision contemplates new rate filings that will be substantially less than the Carriers 2005 and 2006 original filings. This new rate will be similar to the rates proposed by Anadarko/Tesoro. Anadarko/Tesoro's Opinion 154-B TOC interstate rate calculation for transport of a barrel from Pump Station No. 1 to the Valdez Marine terminal is \$2.04 for 2005 and \$1.83 for 2006. Anadarko/Tesoro's calculations shown in Illustration Number 1 above were adopted in this decision. The State's Opinion 154-B reference rate in this proceeding for the interstate rates, for transport of one barrel from Pump Station No. 1 to the Valdez Marine Terminal is \$1.96 and \$2.05 for 2005 and 2006, respectively. The intrastate rate set by the RCA is \$1.96 to transport a barrel of oil from Pump Station

Carriers file a single, uniform tariff annually, rejecting what I think most observers consider to be the State's second most important argument in this case.¹¹

I am also troubled by apparent inconsistencies in some of the State's positions. Here are two examples:

→ The State appears to have reversed itself on one of the fundamental premises of the 1985 TAPS Settlement Agreement between the TAPS Owners and the State, represented by the Department of Law and its consultants. As recently as its 2004 Court appeal of the RCA's 2002 order reducing TAPS tariffs, the State was attempting to argue – in concert with the TAPS Owners – that the 1985 settlement can only be understood as a package established by trade-offs, individual tariff elements spelled out in the settlement and in annual tariff filings have no meaning.¹² But in its Initial Post-Hearing Brief in the CY 2005-2006 FERC tariff proceedings, the State testified that "[t]here can be no genuine debate over the fact that TSM [TAPS Settlement Methodology] depreciation is actual depreciation for ratemaking purposes."¹³

→ In its initial post-hearing brief, the State, through the Department of Law and its consultants, argued that "the State has demonstrated that the reduced intrastate rate ordered by the RCA contributes at least its 'fair share' of earnings required to meet the maintenance and operating costs on TAPS and to yield a fair return on the property."¹⁴ How does the State reconcile its present support of the relatively low TAPS tariff levels it opposed for nearly two decades, and as recently as 2004? And How does the State reconcile its present support of the relatively low TAPS tariff levels it opposed as recently as 2004 with its previous assertions to FERC that the much higher tariffs filed under the 1985 TAPS Settlement Agreement were both "cost-based" and "fair and reasonable"?¹⁵

While both reversals are welcome, their inconsistency with prior stated and vehemently argued positions suggests to me that State tariff argumentation may be driven more by tactical legal maneuvering than by firmly grounded policy considerations. Coming at this

No 1 to the Valdez Marine Terminal. The difference between these rates and the RCA established intrastate rate are minimal. Accordingly, the discrimination has been alleviated and the State's discrimination claims are rendered moot. [Par. 263; citations omitted.]

¹¹ "Initial Decision," p. 110.

¹² State of Alaska, "Appeal of the Regulatory Commission of Alaska's Order No. P-97-4(151)," in *Amerada Hess Pipeline Corporation, et al., vs. Regulatory Commission of Alaska* (State of Alaska Superior Court Case No. 3AN-02-135*12 CI), Mar. 1, 2004, p. 45 (Filed by Senior Assistant Attorney General Janice Gregg Levy, Robert H. Loeffler and Bradley S. Lui, Morrison & Foerster, LLP for Attorney General Gregg D. Renkes.) The State's 2004 appeal referenced the representations of the *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer* at p. 33.

¹³ "Initial Post-Hearing Brief of the State of Alaska," p. 24. (This passage summarizes similar arguments at pp. 3 and 18-23.)

¹⁴ "Initial Post-Hearing Brief of the State of Alaska," p. 86.

¹⁵ See, for example, State of Alaska and United States Department of Justice, *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer* (submitted to Federal Energy Regulatory Commission with settlement offer in Docket No. OR 78-1, etc.), June 28, 1985, pp. 2, 89. (Filed by Attorney General Norman C. Gorsuch and Assistant Attorney General and Robert M. Maynard, State of Alaska, Robert H. Loeffler, Steven S. Rosenthal and W. Stephen Smith, Morrison & Foerster [State of Alaska] and Acting Assistant Attorney General [Antitrust Division] Charles F. Rule, Energy Section Chief Melanie Stewart Cutler and Special Litigation Counsel to the Assistant Attorney General [Antitrust Division] Donald A. Kaplan [U.S. Department of Justice].)

late date, I think it is important to ask how much money the State has lost and how much North Slope development has suffered due to the State's failure to understand and correct its long-held positions on tariff matters in a timely manner.¹⁶

In sum, a slew of important and long-delayed decisions and statements have borne out the long-held concerns of critics of the 1985 TAPS tariff settlement. Since 2002, a series of major legal decisions have fallen like dominoes against the TAPS Owners and against the positions the State argued vociferously until last year. But the fact remains: In the decade since Tesoro filed its first challenge to TAPS in-state tariffs, excessive TAPS tariffs have enabled the TAPS Owners to reduce their payments to the State by more than \$1.1 billion (based on the RCA standard). And as careful examination of the FERC administrative law judge's decision demonstrates, the longer an excessive tariff is in place, the harder it becomes to collect full refunds.¹⁷ In light of the fact (or apparent probability) that refunds will not fully attain that level, I believe the correct standard for State petroleum pipeline tariff policy analysis is to calculate what the State should have received if, instead of pressing its aggressive support of the TAPS Owners' position, the State had operated from its intent, clearly stated on the date of the 1985 settlement, to stand in the shoes of the Shippers.

In preparing for this hearing, I made a list of questions about State petroleum pipeline tariff policy that I wanted to see answered. Based on the difficulty this committee encountered obtaining information on the significance of the FERC Trial Staff's Feb. 16 brief in its March 5 hearing, I thought that a checklist covering background issues and recent developments in this complicated and important area might prove useful today. The twenty questions I came up with cover seven areas:

- Fiscal Impacts of TAPS Tariff Challenges on State Revenue;
- State Position in Current FERC Proceedings;
- Independent Producers and Shippers;
- Duty to Cooperate in Defending the 1985 TAPS Settlement Agreement;
- TAPS Tariffs Under *TSM v. Explanatory Statement* Prognostications;
- Natural Gas Pipeline Tariffs; and
- Tariff Management Issues, including locus of responsibility for setting tariff policy and information about the Department of Law's consultants.

The intent of these questions is to help assess the current TAPS tariff situation, looking forward, and to discover what lessons the TAPS experiences holds for the proposed North Slope natural gas project. To the extent that many of these questions seek historical information, that is because TAPS tariff management issues demonstrate anew, in the Spring of 2007, the maxim of philosopher George Santayana that those who do not understand history are compelled to repeat it. If you find these questions worthy of your attention and you do not have substantive answers to them by the close of this hearing, I respectfully request that you forward them to the Attorney General for his consideration and written response.

¹⁶ During informal discussion, representatives of the Department of Law have told me that I am not giving the State's attorneys and their consultants sufficient credit for their efforts at FERC. One thing I hope to learn from the Department of Law today is exactly what the department believes it has accomplished in the FERC proceeding.

¹⁷ See footnote 6, above.

I. Fiscal Impacts of TAPS Tariff Challenges on State Revenue

1. Fiscal Outcomes of Current Tariff Challenges. During the Mar. 5, 2007 State House Resources Committee hearing on TAPS tariff litigation at FERC, the Department of Revenue was unable to provide written information on its estimate of the fiscal impacts of the tariff case. The department provided a verbal estimate of potential gains to the State Treasury from a litigation victory for years 2005 through 2008 of \$818 million. (Department of Revenue Tax Division Director Jon Iverson told the committee that its estimate was based on work that had just begun that morning; a one-page sheet containing that estimate was sent to legislators shortly after the hearing.) Recently, *Petroleum News* reported that the Department of Revenue now estimates the four-year sums at issue to be about \$600 million.

- A. Please identify the factors that account for the change in the Department of Revenue's latest refund estimate.
- B. When did the Department of Law ask the Department of Revenue to quantify the impacts of the CY 2005 and CY 2006 tariff protests?
- C. When tariffs for CY 2008 will not be filed until December 2007, how was the CY 2008 estimate derived?
- D. When actual tariff data exists for CY 2005 through CY 2007 but future tariff data are not yet available, was it appropriate to include CY 2008 estimates with the three prior years?
- E. Did the Department of Revenue estimate revenue lost, based on the difference between the RCA tariff and the FERC tariff, for CY 2003 and CY 2004, or the full amount of the difference between a timely filing of a TOC tariff and the actual filed TSM?
- F. Why did estimates of future impacts terminate with CY 2008?

2. State CY 2004 TAPS Tariff Overcharge Protest at FERC. The State formally protested certain TAPS tariff charges in the CY 2004 tariff on Dec. 15, 2003. (This protest was not mentioned in the March 5, 2007 State House Resources Committee hearing.)

- A. Please indicate the status or disposition of each of those alleged TAPS tariff overcharges.
- B. Please indicate the estimated amount of the state revenue that was potentially at issue for 2004 and specify whether those amounts were included in the figures presented in response to Question 1, above.

3. State CY 2005 and CY 2006 TAPS Tariff Overcharge Protests at FERC. The State formally protested certain TAPS tariff charges in the CY 2005 and CY 2006 tariffs. (These protests were not discussed in the March 5, 2007 State House Resources Committee hearing.)

- A. Is the State still seeking recovery of revenue lost due to alleged CY 2005 and CY 2006 tariff overcharges by the TAPS Carriers?
- B. If not, how were the State's protests resolved?
- C. If so, please indicate the status of the challenge to each of those alleged TAPS tariff overcharges

- D. Please indicate the estimated amount of the state revenue that was potentially at issue for 2005 and 2006 and specify whether those amounts were included the figures presented in response to Question 1, above.

4. Fiscal Outcomes of Tariff Protests Since 1996. It is conservatively estimated that since Tesoro first protested TAPS tariff overcharges in 1996, the State Treasury has lost at least \$1.1 billion in reduced royalty and tax payments due to TAPS tariff overcharges. Yet, through most of that period, the State, represented by the Department of Law and its consultants, has sided with the TAPS Carriers against challenges to their tariffs. During this period, the State tariff protests filed at FERC by the Department of Law and its consultants sought tariff reductions on specific tariff elements that, in the Department of Law's view, were inconsistent with the 1985 settlement terms (rather than overcharges compared to the statutory standard of a "just and reasonable" tariff under AS 42.06 or comparable federal statutes). The FERC trial staff and ALJ decision confirm that protests under the latter grounds result in much larger refund payments to the State Treasury than protests the State filed.

- A. Please provide estimates of the annual amounts that might be obtained in refunds for tariff items the State has protested during this period as inconsistent with TSM terms.
- B. Please provide comparable estimates of the annual amounts that might have been obtained in refunds for tariff overcharges such as those alleged by Anadarko and Tesoro under the statutory standard of a "just and reasonable" tariff under AS 42.06 or comparable federal statute.

5. Tariffs below TAPS Settlement Agreement Ceiling. In November 1997, the State, led by the Department of Law and its consultants, entered into an agreement with the TAPS Carriers known as the "Capacity Settlement Agreement" (CSA). The CSA was designed to induce rate competition on TAPS, bringing about reduced tariffs over the next decade. According to the Attorney General, "[t]his settlement is historic because it assures competition among pipeline carriers to lower their rates." From testimony in the RCA rate case, it appears that as of 2001 the CSA agreement had resulted in very little rate reduction on TAPS. Moreover, in the decade since the settlement, the TAPS Carriers have increased tariffs significantly.

- A. For oil shipped under FERC tariffs since Jan. 1, 1998, please provide, by year, the average amount per-barrel by which the annual TAPS Settlement Agreement ceiling has exceeded actual TAPS tariffs under FERC jurisdiction.
- B. Have the Department of Law and/or its consultants analyzed the CSA to determine whether excess capacity naturally occurring on TAPS due to reduced throughput would have resulted in (a) the filed below-ceiling tariffs on TAPS and/or (b) additional tariff reductions?
- C. If so, can you provide those analyses?

II. State Position in Current FERC Proceedings

6. Tariff Levels. In the CY 2005-2006 FERC tariff proceedings, the State, through the Department of Law and its consultants, testified that "the State has demonstrated that the reduced intrastate rate ordered by the RCA contributes at least its 'fair share' of

earnings required to meet the maintenance and operating costs on TAPS and to yield a fair return on the property."¹⁸

- A. How does the State reconcile its present support of the relatively low TAPS tariff levels it opposed for nearly two decades, and as recently as 2004?
- B. How does the State reconcile its present support of the relatively low TAPS tariff levels it opposed as recently as 2004 with its previous assertions to FERC that the much higher tariffs filed under the 1985 TAPS Settlement Agreement were both "cost-based" and "fair and reasonable"?¹⁹

7. Depreciation. In its Initial Post-Hearing Brief in the CY 2005-2006 FERC tariff proceedings, the State, through the Department of Law and its consultants, testified that "[t]here can be no genuine debate over the fact that TSM depreciation is actual depreciation for ratemaking purposes."²⁰ But throughout RCA case and as recently as 2004, the State, through the Department of Law and its consultants, argued an apparently contradictory position. For example, in its March 1, 2004 opposition to the RCA decision that TAPS tariff filings were based on a clear statement of annual depreciation laid out in the 1985 settlement, the State argued that "the depreciation schedule in the TSM calculations does not represent a depreciation schedule for TAPS in any conventional sense" and warned that "a rule that a settlement depreciation schedule or any other depreciation schedule not approved for regulatory purposes constitutes 'actual depreciation' will lead to unreasonable results."²¹ The 1985 Settlement Agreement's hyper-accelerated depreciation allowed the TAPS owners early recovery of their expenditures, enabling the TAPS owners to avoid paying refunds. But in 2001 the RCA found – as Tesoro had argued before the FERC – that the Carriers were seeking an unjustified double recovery of depreciation through tariff levels permitted under TSM.

- A. How did the Department of Law and its consultants arrive at the decision to reverse its long-held position that no element of the 1985 settlement can be viewed outside the context of the settlement because TSM is the product

¹⁸ "Initial Post-Hearing Brief of the State of Alaska," in *BP Pipelines (Alaska) Inc., et al.* (FERC Docket No IS05-82-002, etc.), Feb. 16, 2007, p. 86

¹⁹ See, for example, State of Alaska and United States Department of Justice, *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer* (submitted to Federal Energy Regulatory Commission with settlement offer in Docket No. OR 18-1, etc.), June 28, 1985, pp. 2, 89. (Filed by Attorney General Norman C. Gorsuch and Assistant Attorney General and Robert M. Maynard, State of Alaska, Robert H. Loeffler, Steven S. Rosenthal and W. Stephen Smith, Morrison & Foerster [State of Alaska] and Acting Assistant Attorney General [Antitrust Division] Charles F. Rule, Energy Section Chief Melanie Stewart Cutler and Special Litigation Counsel to the Assistant Attorney General [Antitrust Division] Donald A. Kaplan [U.S. Department of Justice])

²⁰ "Initial Post-Hearing Brief of the State of Alaska," p. 24. (This passage summarizes similar arguments at pp. 3 and 18-23.)

²¹ State of Alaska, "Appeal of the Regulatory Commission of Alaska's Order No. P-97-4(151)," in *Amerada Hess Pipeline Corporation, et al., vs. Regulatory Commission of Alaska* (State of Alaska Superior Court Case No. 3AN-02-135112 CI), Mar. 1, 2004, p. 45. (Filed by Senior Assistant Attorney General Janice Gregg Levy, Robert H. Loeffler and Bradley S. Lui, Morrison & Foerster, LLP for Attorney General Gregg D. Renkes.) The State's 2004 appeal referenced the representations of the *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer* at p. 33.

of a negotiated settlement involving many inter-related compromises and tradeoffs?²²

- B. Could a better explanation for this switch in a long-held position have enhanced the State's credibility in this proceeding?
- C. Why did it take the Department of Law and its consultants 20 years to recognize that the Carriers' tariff filings under TSM were double-counting depreciation expenses to overcharge independent shippers?

8. Per-Barrel Allowance. Some observers believe that the 1985 TAPS Settlement Agreement departed significantly from principles of cost-based ratemaking by replacing the return profit calculation applied through 1989 with a per-barrel allowance (inflation-adjusted annually from a CY 1983 starting point of \$0.35 per barrel). Under the 1985 agreement, beginning in 1990 the major profit element on TAPS was no longer related to the costs incorporated in the rate base.

- A. Have the Department of Law and its consultants compared the amounts the TAPS Carriers have gained through tariff collections realized through the inflation-adjusted per-barrel allowance in effect under TSM since 1990, plus other profit elements, to an allowable standard rate of return profits on a depreciated rate base under a standard cost-based ratemaking method?

9. May 17, 2007 FERC Administrative Law Judge Decision. The FERC Administrative Law Judge supported the A/T arguments, and recommended that the commission order reduced tariffs filed by the TAPS Carriers from over \$5.00 per barrel to a level approaching the \$1.96 per barrel tariffs ordered by the RCA in 2002 for in-state shipments, thus rendering moot the Department of Law's petition for a lower tariff on grounds of discrimination under the Interstate Commerce Act.

- A. Please identify the specific items in the ALJ decision in which the State believes it achieved significant victories.
- B. For each point on which the State believed it achieved significant gains, please provide a statement of the fiscal impact of each item and/or a brief summary of the policy implications of that item.

III. Independent Producers and Shippers

9. The State and Independent Producers/Shippers. According to the Explanatory Statement on the 1985 settlement agreement, because there is no other practical means to ship oil from the North Slope, "Alaska stands in the shoes of both past and future shippers Alaska's interests are coextensive with shippers."²³

- A. How do the Department of Law and its consultants reconcile the State's prolonged opposition to independent shipper challenges to excessive TAPS tariffs with its assertions (e.g., in the Explanatory Statement accompanying

²² State of Alaska and United States Department of Justice, *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer* (Federal Energy Regulatory Commission, Docket No. OR 78-1, etc., pp 3-4 (quoted in State Brief, Mar. 1, 2004, pp. 22-33).

²³ *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer*, p. 18.

the submission of the 1985 settlement agreement to FERC) that Alaska stands in the shoes of the shippers?

- B. Does the prolonged levy of excessive TAPS tariffs handicap independent producers, who must pay the excess tariffs out of pocket?
- C. Does the prolonged levy of excessive TAPS tariffs have a chilling effect on North Slope exploration and development by companies other than the TAPS owners?

10. Excess Tariff Handicaps to Independent Shippers. The FERC Administrative Law Judge concluded, citing A/T's numbers for CY 2006, that adoption of TOC (Trended Original Cost) methodology for TAPS would produce a tariff very near that of the RCA's DOC (Depreciated Original Cost) tariff. Using A/T's comparison of that rate to the TAPS Carriers' rejected proxy tariff, it appears that the major differences between the A/T TOC tariff of \$2.04 per barrel and the TAPS Carriers' rejected TOC tariff of \$5.53 per barrel are: Return Allowance ("return on equity"), Depreciation, Deferred Earnings and Income Tax Allowance. The first two items are associated, respectively, with Items 7. and 8., above; the third item represents payments to the Carriers for trending (inflation-adjusting) the rate base; the final item represents collections from shippers to pay the income tax on pre-tax net revenue. These four items represent charges in excess of a "fair and reasonable" or "just and reasonable" tariff, both of which allow the Carriers a reasonable return on their property.

- A. When a TAPS Owner ships its own oil, tariff charges in excess of actual costs represent internal transfer payments between the production and the transportation arms of the company. In contrast, the independent shipper must pay these costs out of pocket. Has the Department of Law asked its consultants or the Department of Revenue to quantify the handicap to independent shippers on TAPS of excess charges under the TAPS Settlement Methodology?
- B. If so, please provide that information on an aggregate and a per-barrel basis.
- C. Compared to TAPS tariffs filed under the 1985 settlement methodology, correction of these four specific tariff elements in the filed 2006 tariffs would reduce TAPS tariff revenue by approximately 60% (from more than \$5.00 per barrel to approximately \$2.00 per barrel). By comparison, if the State prevailed in its protest of specific elements of the 2006 tariff, what would the reduction to TAPS tariffs have been on an aggregate and a per-barrel basis?
- D. For CY 2003, 2004 and 2005, following the A/T methodology please provide the amounts of corrections to the four specific tariff elements discussed in this question on an aggregate and per-barrel basis.
- E. By comparison, For CY 2003, 2004 and 2005, if the State were successful in its protest of specific tariff elements, what would the reduction to TAPS tariffs have been on an aggregate and a per-barrel basis?

11. Antitrust Issues. In a 1996 interview, Conoco CEO Archie Dunham discussed Conoco's 1993 trade of its Milne Point field to BP for a Gulf of Mexico property and its departure from Alaska with *Hart's Oil & Gas Investor*. At the time of its departure from Alaska in 1993, Conoco was the only independent (non-TAPS owner) field operator on the North Slope. In the 1996 interview, Dunham commented: "It broke my heart to trade

Milne Point but we had to do it. All the value of that property was taken away from us in the pipeline tariffs."²⁴ In 1997 Maritime Endeavor, an independent tanker company, filed an antitrust suit against the TAPS Owners and Alyeska Pipeline Service Co. in federal court in Juneau, alleging that the TAPS owners were violating antitrust law by using technical requirements to prevent an independent tanker from serving the Alyeska terminal.²⁵ In October 1997, I prepared a report on TAPS antitrust issues for Oilwatch Alaska, in which I recommended that the Department of Law look into the issues raised in that report to ensure competition on the North Slope.²⁶ The Department of Law declined to undertake that investigation.

- A. When did the Department of Law become aware of Mr. Dunham's statement and what action did it take to determine whether there was a relationship between pipeline tariffs and the departure from Alaska of the only independent operator on the North Slope?
- B. When did the Department of Law become aware of the Maritime Endeavor case and what action did the Department of Law take to determine whether the company's complaint had merit?
- C. Are the Department of Law and its consultants aware of any other state or region producing more than 500,000 bpd in which (1) the only link to market is dependent on largely producer-owned transportation links whose average cost exceeds \$4.00 per barrel and/or (2) three or fewer producers own more than 95% of the only pipeline link to market and control a similar share of production?

IV. Duty to Cooperate in Defending 1985 TAPS Settlement Agreement

12. Duty to Cooperate in Defending the 1985 TAPS Settlement Agreement. It has been suggested that the State, represented by the Department of Law and its consultants, actively opposed the protests of Tescro and other independent shippers at the RCA (and its predecessor, the APUC) for the first 7-1/2 years of this case – and is currently limited in its grounds for protesting TAPS tariffs at FERC – because Section 1-3 of the 1985 TAPS Settlement Agreement between the State and the Carriers requires that each party "cooperate . . . at its own expense . . . in defending against any litigation affecting the validity and enforceability of this Agreement, or any provision thereof." After opposing the independent shippers at the APUC/RCA for approximately eight years, on Feb. 28, 2006, the State, represented by the Department of Law and its consultants, served notice that the State was withdrawing from case and would not be appearing before the State Supreme Court in the final argument on that case.

²⁴ "Getting to the Future First" (interview by Leslie Haines), *Hart's Oil and Gas Investor*, August 1996, p. 39

²⁵ This antitrust complaint (filed in U.S. District court, Juneau, by Maritime Endeavor Associates, LP against Alyeska Pipeline Service Company, Inc., and its owners [Case No. J97-010 CV (HRH)], May 27, 1997) was filed along with a companion breach of contract case filed in state court. The state case went first; in that case, the judge decided in favor of Maritime and awarded the plaintiffs a \$10 million judgment (Judge Walter Carpinetti, "Memorandum of Decision and Order," in *Maritime Endeavor Associates, LP against Alyeska Pipeline Service Company* [Case No. 1JU-95-1141 CI], Sept. 30, 1998). The decision was vacated and settled out of Court – reportedly for approximately \$10 million. As part of the final settlement, Maritime dropped the federal antitrust charge.

²⁶ Richard A. Fineberg, *The Big Squeeze: TAPS and the Departure of Major Oil Companies Who Found Oil on Alaska's North Slope* (Oilwatch Alaska, Oct. 23, 1997)

- A. Since the State evidently did not deem itself contractually bound to join the TAPS Carriers in actively defending the 1985 TAPS Settlement Agreement after Feb. 28, 2006, what factors prompted the State oppose the challenges of independent TAPS shippers at the RCA between 1996 and February 28, 2006, despite the fact that reduced tariffs would augment State revenue and promote competition on the North Slope by independent developers?

13. Definition of Duty to Cooperate in Defending the 1985 TAPS Settlement Agreement.

The 1985 agreement uses ten pages to describe the elements of the settlement methodology and contains an additional three page "Index of Defined Terms." Neither set of definitions makes reference to Sec. I-3 of the Settlement.

- A. Has the Department of Law attempted to determine the extent to which Sec. I-3 constrains the State's current challenges to TAPS tariffs?
- B. Has the Department of Law ever attempted to determine the legal extent to which Sec. I-3 of the 1985 settlement agreement constrained the State's challenges of possible or actual TAPS tariff overcharges between 1986 and the the present?
- C. If so, please (1) indicate the dates that written documents on this subject were prepared and (2) provide those documents.

V. TAPS Tariffs Under TSM v. Explanatory Statement Prognostications

14. Tariff Levels under TSM (1990-2011): According to the 1985 Explanatory Statement, tariff levels between 1990 and 2011 would be comparable to a DOC tariff and far lower than tariff implementing a TOC methodology.²⁷ However, (1) the RCA has determined that TSM permitted overcharges of nearly \$10 billion through 1996, compared to a DOC tariff, and (2) the standard TOC tariff recommended b by the FERC ALJ would reduce current TAPS tariffs by more than 60%. The FERC Trial Staff and Administrative Law Judge agree that a properly implemented TOC tariff would produce current TAPS tariffs to levels very near that of a DOC tariff.

- A. What accounts for the radically differences between (a) the tariff outcomes calculated by the RCA and the FERC Trial Staff and Administrative Law Judge and (b) the prognostications of the 1985 *Explanatory Statement*?
- B. Please compare TAPS throughput from Jan. 1, 1986 through Dec. 31, 2006 to the forecast figures used in the Explanatory Statement prognostications?
- C. All other things being equal, in comparing actual results to 1985 projections, shouldn't increased production and reduced federal income tax rates have resulted in decreased tariffs, compared to 1985 projections?

15. Other Representations. In the 1985 Explanatory Statement, the Department of Law and its consultants asserted that "[t]he TAPS Settlement Agreement resolves all outstanding issues of dispute in regard to the settling carriers' TAPS tariffs." Moreover,

²⁷ *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer*, pp. 88-89 and Appendices 7, 8

the Explanatory Statement asserted, "[f]rom an administrative standpoint, the TSM will be practically as easy to administer as any other methodology."²⁸ In expressing the State's strong support for the maintaining the 1985 settlement at the start of the RCA hearing in April 2001, the State's consulting counsel told the RCA that the 1985 TAPS Settlement Agreement "has performed better than expected."

- A. In view of the facts that (a) tariffs under the 1985 settlement were significantly higher than a standard DOC tariff would have been and (b) the RCA, FERC Trial Staff and FERC Administrative Law Judge concur that actual tariffs filed in compliance with the settlement agreement have been excessive, what is the basis for the prognostications of the 1985 *Explanatory Statement* and the 2001 statements of the Department of Law's counsel, on behalf of the State, to the RCA?

16. Dismantling, Removal & Restoration (DR&R). This element of the 1985 TAPS Settlement, codified in Sec. II-4 and Exhibit E delivered a significant, off-book giveaway to the TAPS Carriers over and above the amounts indicated by the reckonings in Items 1 through 5 and 13, above. Although settlement presentations to the State Legislature (and the 1985 *Explanatory Statement*) misleadingly glossed over the gargantuan giveaway resulting from this settlement element, in 1986, the Alaska Public Utilities Commission Staff Expert Witness authoritatively explained that the accelerated over-collection and failure to escrow these sums would increase the off-book, after-tax gains to the TAPS owners by more than \$7.0 billion.²⁹ A/T's current updating of that calculation indicates that the gains to the TAPS Owners will be more than twice that amount. Although more than 99 percent of those funds have already been collected from TAPS shippers through the accelerated terms in TAPS Settlement Exhibit E, the status and management of those funds is still at issue. In light of this background:

- A. What specific settlement benefits did the State receive from granting, through the 1985 settlement, DR&R collection terms to the TAPS owners that, according to the 1986 calculations of the APUC Staff Expert Witness, increased the estimated settlement gains to the TAPS Owners by more than 50 percent?
- B. In the two decades since this defect in the 1985 Settlement terms was identified and the resulting after-tax, off-book gains to the TAPS Owners were quantified, what steps did the Department of Law and its consultants take to remedy this situation?
- C. In 2000, the Department of Law became aware that a 1988 ruling by the U.S. Internal Revenue Service increased the tariff gains to TAPS Owners by making the DR&R pre-collections (which had been "grossed up" under the settlement terms to pay federal income tax) tax-deductible. At that time, the attorney representing the Department of Law promised the Legislature the attorneys and accountants would get to the bottom of this issue and remedy

²⁸ *Explanatory Statement of the State of Alaska and the United States Department of Justice in support of Settlement Offer*, pp. 17, 66.

²⁹ Prefiled Testimony of Rudolph L. Bertschi (Alaska Public Utilities Commission Docket No. P-86-2, Dec. 17, 1986), pp. 63-70 and Exhibits RLB-15, Schedules 1 and 2 (Reprinted in Appendix C of this writer's *Hidden Billions: The TAPS DR&R Provision* [report to Stan Stephens, August 21, 1992], pp. 47-57.)

it.³⁰ What substantive actions (if any) have the Department of Law and its consultants taken in the intervening six years to remedy this problem and what is the status of these efforts?

(VI.) Natural Gas Pipeline Tariffs

17. Sensitivity to Pipeline Tariffs. On a BTU equivalent basis, natural gas tariffs constitute a significantly greater percentage of the commodity price than oil pipeline tariffs. For example, Econ One places the gas tariff to Alberta (with conditioning plant costs) at approximately \$1.50 per mmBTU.³¹ By comparison, the average barrel of oil produces 5.8 mmBTU. Therefore, an oil tariff of \$2.00 to \$5.00 per barrel is transporting an equivalent commodity for somewhere between \$0.34 to \$0.90 per mmBTU, depending on the tariff. The figures above suggest that natural gas pipeline tariffs, as a percentage of the commodity price, would be somewhere between 66% and 340% greater than oil pipeline tariffs. It appears from this calculation, that both the viability of the project and State revenue are much more dependent on tariff decisions than the oil pipeline.

- A. Has the State prepared estimates of project tariffs for a proposed natural gas line? If so: (1) What is the range of the tariff estimate per mmBTU? (2) Does the variation in estimates reflect (a) differences in project costs, (b) uncertainty about FERC inputs, treatment of costs and other factors critical to tariff methodology, or (c) both?
- B. Does the EconOne estimate of approximately \$1.50 per mmBTU, plus or minus 20%, incorporate uncertainty about FERC inputs, treatment of costs and other factors critical to tariff methodology?
- C. Does the State believe that natural gas trades at a discount to oil? If so, does that discount factor increase project sensitivity to tariffs?

18. Strategies to Reduce Sensitivity to Pipeline Tariffs. The history of the TAPS tariff implementation suggests that the State (a) rewarded bad behavior by the industry in 1985 by caving in on cost over-runs, refunds and other major tariff issues when it entered into the TAPS Settlement Agreement and (b) after three decades of operation, has yet to secure just and reasonable tariffs on TAPS, to the detriment of State revenue and development.

- A. Have State tariff managers presented a strategy (with timelines for data submission and analysis, agency and court review procedures) that will ensure that just and reasonable gas pipeline tariffs are established in a timely manner?

³⁰ See: Richard Fineberg, "New filings reveal oil pipeline owners' tax scam," *Anchorage Daily News* (Compass), Feb. 8, 2000, p. B-8; Richard A. Fineberg, "Federal Income Tax Payments on Dismantling Element of the Trans-Alaska Pipeline System (TAPS) Tariff" (corrected final testimony before the Alaska State House Oil & Gas Committee, April 13, 2000); and Letter from Attorney General Bruce M. Botelho (signed by Assistant Attorney General Michael A. Barnhill), May 23, 2000.

³¹ Adapted from Anthony Finizza (consultant to Econ One), "Natural Gas Prices and Tariffs," presented to State Legislative Budget and Audit Committee, Aug. 31, 2005, pp. 16-17. (2005 estimates adjusted to reflect inflation and current prices; Dr. Finizza estimated that this tariff estimate could be 20% high or low.)

- B. On May 12, 2006, a Department of Law consultant representing the Administration assured legislators that, at least in theory, producers could be expected to contain pipeline costs to a greater extent than independent pipeline builders because, as shippers, they would have to pay the tariff. (1) Has the Department of Law explained the apparent contradiction between the historical reality of TAPS tariff charges and his statement?

(VII.) Pipeline Tariff Management Issues

19. Payments to Department of Law Consultants. Between 1981 and June 30, 1997, the Department of Law paid Morrison & Foerster and its associates more than \$20 million for legal assistance associated with TAPS tariffs. During the 1980s, payments averaged approximately \$1.0 million per year, increasing to about \$1.5 million per year during the 1990-93 period and \$2.1 million per year between Jan. 1, 1994 and June 30, 1997.³²

- A.. Does this amount include payments to accountants working with Morrison & Foerster, including Dr. Thomas Horst?
- B. How much did the State of Alaska pay Morrison & Foerster and its associates, including Dr. Thomas Horst, for work on TAPS tariff issues between July 1, 1997 and June 30, 2003?

According to the *Alaska Budget Report*, between July 2003 and the end of 2006 the State paid the law firm of Morrison & Foerster . \$12,268,896 million for legal services and negotiations.

- C. Does the \$12.3 million payments to Morrison & Foerster between July 2003 and the end of 2006 include payments for work on TAPS, including payments to Dr. Thomas Horst, for work on TAPS tariff issues?
- D. Between July 2003 and the end of 2006, how much did the State of Alaska pay Morrison & Foerster and its associate accountants, including Dr. Thomas Horst, for work on TAPS tariff issues?

20. Responsibility for State Pipeline Tariff Policy. The Alaska Pipeline Act lists ten general powers and duties of the RCA under which that agency regulates pipelines and pipeline carriers in the state. The final subsection states that the commission

(10) shall provide all reasonable assistance to the Department of Law in intervening in, offering evidence in, and participating in proceedings involving a pipeline carrier or affiliated interest and affecting the interests of the state, before an officer, department, board, commission, or court of another state or the United States.³³

³² Alaska Dept. of Law, "Oil & Gas Contract Summary, 1977-February 15, 1994" [attachment to letter from Attorney General Bruce Botelho to House Finance Committee Co-Chair Ron Larson, Feb. 17, 1994], supplemented by personal communication from Alaska Department of Law, August 1997

³³ AS 42 06 140(a)(10)

- A. Apart from this statutory reference to the Department of Law, please identify any statutes that specifically assign responsibility for pipeline tariff policy to the Department of Law.
- B. The various sections of the Civil Division of the Department of Law handle legal matters and provide legal advice to the agencies of the executive branch. What state agency has statutory authority to set and review pipeline tariff policies?
- C. Please identify any functions of State government for which the Civil Division of the Department of Law not only handles legal matters associated with implementing policy, but also has (1) statutory and/or (2) *de facto* responsibility for setting and reviewing that policy.

Again I want to thank you for your efforts in this important area.

Secs. 42.06.010 — 42.06.120. Legislative policy; Alaska Pipeline Commission. [Repealed, § 20 ch 110 SLA 1981.]

Sec. 42.06.130. [Renumbered as AS 42.06.605.]

Article 1. Powers and Duties of Regulatory Commission of Alaska.

Section	Section
55. Commission decision-making procedures	210. Publication of reports, orders, decisions, and regulations
140. General powers and duties	220. Annual report
150. Powers and duties with respect to federally regulated carriers	230. Jurisdiction of commission

Sec. 42.06.055. Commission decision-making procedures. The commission shall comply with AS 42.04.080 for matters that come before the commission for decision. (§ 16 ch 25 SLA 1999)

Effective dates. — Section 31(c), ch. 25, SLA 1999 makes this section effective July 1, 1999

Sec. 42.06.140. General powers and duties. (a) The commission

- (1) shall regulate pipelines and pipeline carriers in the state;
- (2) may investigate upon complaint or its own motion, the rates, classifications, rules, regulations, prices, services, practices, and facilities of pipeline carriers, and the performance of obligations under and compliance with the terms of leases issued by the state;
- (3) may make, prescribe, or require just, fair, and reasonable rates, classifications, regulations, practices, services, and facilities for pipeline carriers;
- (4) may require pipeline carriers and affiliated interests to file with the commission reports and other information and data required or permitted to be required by other provisions of this chapter;
- (5) may adopt regulations that are necessary and proper to the performance of its duties under this chapter, including regulations governing practices and procedures of the commission; the regulations may not be inconsistent with state law;
- (6) shall during normal business hours have access to and may designate any of its employees, agents, or consultants to inspect and examine the accounts, financial and property records, books, maps, inventories, appraisals, valuations, and related reports kept by a pipeline carrier, or kept for it by others, that directly affect the interests of the state and directly relate to pipelines located in the state;
- (7) may initiate, intervene in, and appear personally or by counsel and offer evidence in and participate in, any proceedings involving a pipeline carrier, and affecting the interests of the state, before any officer, department, board, commission, or court of this state;
- (8) shall require permits for the construction, enlargement in size or operating capacity, extension, connection and interconnection, operation or abandonment of any oil or gas pipeline facility or facilities, subject to necessary and reasonable terms, conditions and limitations;
- (9) may prescribe the system of accounts and regulate the service of an oil or gas pipeline facility;
- (10) shall provide all reasonable assistance to the Department of Law in intervening in, offering evidence in, and participating in proceedings involving a pipeline carrier or affiliated interest and affecting the interests of the state, before an officer, department, board, commission, or court of another state or the United States.

(b) The law judge chapter. 'administ conduct l five years am §§ 1,

Revisor' AS 42.05.1:

Constit AS 42.06, 1 Pub. Util.

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DUTY TO DEFEND

The State is party to a Settlement Agreement with the TAPS Carriers that was executed by the parties and approved by the FERC in 1985. I'll refer to that settlement as the TSA. The TSA is a legally binding contract between its parties, and its term runs through at least the end of 2008.

The TSA provides a formula and criteria under which the Carriers annually calculate and file new TAPS rates.

The TSA expressly requires the parties to defend against any litigation that affects the validity and enforceability of the Agreement, or any provision thereof. [Section I-3]

This duty to defend is a contractual duty, and in essence it requires the State to support and defend TAPS rates filed in conformance with the TSA.

If the State were to protest TSA--conforming TAPS rates at the FERC, the TAPS Carriers would surely petition the FERC to dismiss the State Protest (as they have repeatedly done in the current FERC litigation), and in our judgment, the FERC would dismiss the State to keep it from breaching its FERC-approved contract.

STATE'S DISCRIMINATION PROTEST

In December 2004, the TAPS Carriers filed 2005 interstate rates for TAPS shipments from PS-1 to Valdez that averaged \$3.71 / bl.

The RCA-regulated intrastate rates for shipments from PS-1 to Valdez have remained at \$1.96 / bl since the RCA's decisions on Tesoro's protests in dockets P-97-4 and P-03-4.

Thus, the 2005 TAPS rates for identical shipping services varied by \$1.75 / bl depending on whether the shipments were in interstate or intrastate commerce.

The final paragraph of the TSA rate methodology [II-11(e)] provides that 'notwithstanding any other provision of the TSA, rates charged for TAPS services are subject to legal prohibitions on unjust discrimination and undue preference.' [paraphrased]

In other words, rates that are unjustly discriminatory or unduly preferential are not TSA conforming rates.

The TSA duty to defend applies only to TSA conforming rates, and thus does not apply to unjustly discriminatory rates. The State therefore protested the TAPS 2005 interstate rates on the grounds of unjust discrimination and undue preference.

The legal prohibitions on unjust discrimination and undue preference are set out in sections 2 and 3 of the Interstate Commerce Act. The ICA was enacted in 1885, and there is a long history of rate discrimination caselaw to rely on in applying its terms.

The basic premise of the ICA discrimination caselaw is that rates charged for substantially identical services must be substantially identical. Thus the State's protest cites to the nearly double rates charged for interstate vs intrastate services on TAPS as proof of unjust discrimination.

The remedy for unjust discrimination under ICA section 2, is to reduce the higher rate to a level comparable to the lower rate. The State is therefore seeking to have the interstate TAPS rate reduced to approximately the level of the \$1.96 intrastate rate.

PROCESS THROUGH HEARING

The State initiated the current litigation by filing its discrimination protest of the 2005 TAPS rates. A day after the State filed its protest, Anadarko and Tesoro jointly filed a protest of the 2005 TAPS rate on separate grounds. The FERC consolidated the protests for hearing. The parties have since continued their protests on the TAPS 2006 and 2007 rates, on the same grounds

Anadarko / Tesoro are not parties to the TSA. They are not subject to the duty to defend and have taken no position in this litigation on whether the 2005, 2006 and 2007 TAPS rates are calculated and filed in conformance with the TSA.

A/T instead challenges the rates as not in conformance with the FERC **non-settlement** rate methodology -- the "Opinion 154-B" methodology.

In response to the A/T evidence regarding its TAPS 154-B calculation, the TAPS Carriers filed their own (much higher) 154-B calculation.

In response to the State's discrimination protest, the Carriers claimed that their 154-B calculation showed that the intrastate rate was too low, and that any discrimination should be alleviated by increasing the intrastate rate.

The State therefore responded by presenting its own 154-B reference rate calculation, and thereby established that the \$1.96 intrastate rate did indeed cover its fair share of the costs of TAPS operations. The State's 154-B

evidence presents rates and rate components very close to those presented by A/T.

The focus of the litigation thus became an argument over the proper calculation of non-settlement 154-B rates for TAPS.

JUDGE CINTRON'S DECISION

Following a lengthy review of the filed testimony and arguments from all of the parties regarding the appropriate calculation of TAPS rates under the 154-B methodology, Judge Cintron ruled in favor of A/T's protest and found that the Carriers should be required to file new rates going forward (after 2006) at approximately \$2 / bl.

She then moves on to address the State's discrimination claim, and in paragraph 263, at pages 112-113 she rules:

"this decision contemplates new rate filings that will be substantially less than the Carriers 2005 and 2006 original filings . . . A/T's Opinion 154-B interstate rate calculation . . . is \$2.04 for 2005 and \$1.83 for 2006. The State's Opinion 154-B reference rate . . . for interstate rates . . . is \$1.96 and \$2.05 for 2005 and 2006, respectively. The intrastate rate set by the RCA is \$1.96 . . . THE DIFFERENCE BETWEEN THESE RATES AND THE RCA ESTABLISHED RATE ARE MINIMAL. ACCORDINGLY, THE DISCRIMINATION HAS BEEN ALLFVIATED AND THE STATE'S DISCRIMINATION CLAIMS ARE RENDERED MOOT.

In summary, Judge Cintron found that by equalizing the TAPS interstate and intrastate rates going forward, her ruling for Anadarko/Tesoro alleviated the discrimination.

Now that sounds reasonable, as far as it goes, HOWEVER

the State's discrimination protest does not seek relief only from discrimination in rates charged after 2006, we also seek to cure the discrimination in rates already charged in 2005 and 2006.

And in ordering refunds for 2005 and 2006, Judge Cintron ignores our discrimination protest (which she found to be moot) and relies on a legal precedent that has applied only in a select few J&R -- that is, non-discrimination -- rate cases.

The precedent she relies on limits refunds to the difference between the rates actually charged and the last permanent (unprotested) rate that was in effect prior to the filing of the current protested rate. In this case she ruled that the 2004 TAPS rate was the "last legal rate" for calculation of refunds.

So, based on that narrow precedent, Judge Cintron has limited the refunds for 2005 and 2006 to the difference between the TAPS rates charged and the 2004 TAPS rate -- which averaged about \$3.05 / bl.

Her decision to limit the refunds is subject to legal challenge even when applied in the context of a J&R rate protest, and the FERC staff has well presented that legal challenge in their Reply Brief.

The State has an alternative, perhaps stronger, argument to raise against the refund limitation ruling through its discrimination protest.

That's because, under ICA Sections 2 and 3, rates that are unjustly discriminatory and/or unduly prejudicial are illegal, and the remedy for such illegal rates is to remove all of the discrimination by resetting the interstate rates at a level comparable to the lower intrastate rate charged for comparable services.

Judge Cintron acknowledged this requirement for equivalence in the interstate and intrastate rates when she determined (as I quoted earlier)

that by setting interstate rates that are "minimally" different from the intrastate rates, she had "alleviated" the rate discrimination protested by the State.

However, the effect of her proposed refund decision is to allow the Carriers to retain tariff payments at a \$3.05 / bl rate for 2005 and 2006.

This is still \$1 more than the \$1.96 intrastate rate or than the rate that she established as J&R for 2005 forward.

Her refund decision thus does not create the "minimal" difference between interstate and intrastate rates that she relied upon to support her finding that the State's discrimination claim is moot.

STATE'S RESPONSE

So, where do we go from here?

The State is considering possibly filing exceptions to Judge Cintron's decision along the following lines:

First that the State's discrimination claim is not moot since, as the judge's refund decision shows, different rules apply to the calculation of refunds in J&R rate litigation, as opposed to in discrimination litigation, and

Second, that allowing the Carriers to retain a \$3.05 / bl rate in calculation of the refunds for 2005 and 2006, does not appropriately remedy the discrimination in rates for those years. In accordance with her ruling on the discrimination claim, the refunds must result in no more than minimal differences between the TAPS interstate and intrastate rates for 2005 and 2006, as well as going forward.

UNITED STATES OF AMERICA 119 FERC ¶ 63,007
FEDERAL ENERGY REGULATORY COMMISSION

BP Pipelines (Alaska) Inc.	Docket No. IS05-82-002
ConocoPhillips Transportation Alaska Inc.	Docket No. IS05-80-002
ExxonMobil Pipeline Company	Docket No. IS05-72-002
Koch Alaska Pipeline Company LLC	Docket No. IS05-96-002
Unocal Pipeline Company	Docket No. IS05-107-001

State of Alaska	Docket No. OR05-2-001
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v.

BP Pipelines (Alaska) Inc
ExxonMobil Pipeline Company
ConocoPhillips Transportation Alaska, Inc.
Unocal Pipeline Company
Koch Alaska Pipeline Company

Anadarko Petroleum Corporation	Docket No. OR05-3-001
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v.

TAPS Carriers

BP Pipelines (Alaska) Inc.	Docket No. OR05-10-000
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BP Pipelines (Alaska) Inc.	Docket No. IS06-70-000
ExxonMobil Pipeline Company	Docket No. IS06-71-000
ConocoPhillips Transportation Alaska, Inc.	Docket No. IS06-63-000
Unocal Pipeline Company	Docket No. IS06-82-000
Koch Alaska Pipeline Company	Docket No. IS06-66-000

Anadarko Petroleum Corporation	Docket No. OR06-2-000
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v.

TAPS Carriers

INITIAL DECISION

(Issued May 17, 2007)

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CARMEN ANA CINTRON, Presiding Administrative Law Judge

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I. INTRODUCTION

1. This case set for hearing the 2005 and 2006 interstate rate filings of the TAPS Carriers.¹ This decision finds that the proposed interstate rates for 2005 and 2006 are not just and reasonable.

II. PROCEDURAL HISTORY

2. The “labyrinthine regulatory process” leading to the Commission’s approval of the TAPS Settlement Agreement (TSA) is set forth in *Arctic Slope Regional Corporation v. FERC*, 832 F.2d 158 (D.C. Cir. 1987), and is not repeated here. The stipulated procedural history of the case is described below.²

3. In December of 2004, the TAPS Carriers filed their interstate rates for 2005, which ranged from \$3.52 to \$3.97 per barrel, for the transportation of ANS crude oil from Pump Station No. 1 to the southern terminus of TAPS at the Valdez Marine Terminal (Valdez). On December 15, 2004, the State of Alaska (State) filed a protest of the TAPS Carriers’ 2005 filed rates and a complaint with respect to the TAPS Carriers 2003 and 2004 filed rates (State’s 2005 Protest and Complaint).³

4. In its 2005 Protest and Complaint, the State alleged that the TAPS Carriers’ 2005 filed rates (1) violated the unjust discrimination and undue preference provisions of sections 2 and 3(1) of the Interstate Commerce Act (ICA), (2) were inconsistent with the terms of the Interstate Settlement Agreement, (3) impermissibly included dismantlement, removal, and restoration (DR&R) expenditures as Operating Expenses, and (4) unlawfully included non-jurisdictional intrastate litigation costs. The State also protested (5) ConocoPhillips’ alleged failure to make the required section II-10 adjustment to its 2005 maximum allowable rate under the TAPS Settlement Methodology (TSM), and (6) ConocoPhillips’, Unocal’s, and KAPL’s alleged inclusion in their 2005 interstate tariffs of the intrastate portion of the DR&R Allowance that they had waived before the Regulatory Commission of Alaska (RCA).

¹ The TAPS Carriers, or Carriers, are BP Pipelines (Alaska) Inc. (BP), ConocoPhillips Transportation Alaska Inc. (ConocoPhillips), ExxonMobil Pipeline Company (ExxonMobil), Koch Alaska Pipeline Company LLC (KAPL), and Unocal Pipeline Company (Unocal).

² The procedural history was submitted pursuant to an order of the Presiding Judge. Tr. at 6942-43 (January 11, 2007).

³ “*Protest and Petition for Investigation into the Proposed 2005 TAPS Tariffs and Complaint and Petition for Investigation into the 2003 and 2004 TAPS Tariffs by the State of Alaska and Intervention in Any Subsequent Proceedings*,” Docket No. OR05-2-000 (Dec. 15, 2004).

Further, the State complained that the TAPS Carriers' 2003 and 2004 interstate tariffs impermissibly included (7) non-jurisdictional intrastate litigation costs, and (8) DR&R expenses. The State subsequently reached a settlement with ConocoPhillips and withdrew the portions of its 2005 Protest and Complaint dealing with items (5) and (6) (as it pertained to ConocoPhillips).⁴ The State also reached settlements with KAPL and Unocal, and withdrew the portions of its 2005 Protest and Complaint concerning item (6) (as it pertained to KAPL and Unocal).⁵ On October 11, 2006, the State withdrew the portion of its 2005 Protest and Complaint concerning items (4) and (7).⁶ On March 6, 2006, the Presiding Judge clarified that item (3) was to be considered along with the investigation of Strategic Reconfiguration Program costs in a later phase of the proceeding.⁷ Items (1), (2) and (8), therefore, are the portions of the State's 2005 Protest and Complaint that remain at issue in this phase of the proceeding.

5. On December 16, 2004, Anadarko Petroleum Corporation (Anadarko) filed a protest and complaint (Anadarko's 2005 Protest and Complaint) alleging that the TAPS Carriers' 2005 filed rates were unjust, unreasonable and otherwise unlawful.⁸

⁴ "Notice of Partial Withdrawal of State's Protest and Complaint Against ConocoPhillips Transportation Alaska Inc.," Docket Nos. IS05-80 and OR05-2 (Sept. 7, 2005); "Notice of Partial Withdrawal of State's Protest and Complaint Against ConocoPhillips Transportation Alaska Inc.," Docket Nos. IS05-80 and OR05-2 (Nov. 2, 2005); "Order Granting Partial Withdrawals," Docket Nos. IS05-82-002, *et al.* (Nov. 4, 2005).

⁵ "Notice of Partial Withdrawal of State's Protest and Complaint Against Koch Alaska Pipeline Company LLC," Docket Nos. IS05-82, *et al.* (Jan. 24, 2006); "Order Confirming Partial Withdrawal," Docket Nos. IS05-82-002, *et al.* (Feb. 9, 2006); "Notice of Partial Withdrawal of State's Protest and Complaint Against Unocal Pipeline Company," Docket Nos. IS05-82, *et al.* (April 20, 2006); "Order Confirming Partial Withdrawal," Docket Nos. IS05-82-002, *et al.* (May 18, 2006).

⁶ "Notice of Partial Withdrawal of State's Protests and Complaints Against BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company, Koch Alaska Pipeline Company LLC, and Unocal Pipeline Company," Docket Nos. IS05-82-002, *et al.* (Oct. 11, 2006) (State's October 11, 2006 Notice);

⁷ "Order Establishing New Procedural Schedule, Granting Request for Clarification and Confirming Withdrawal of Motion to Amend Procedural Schedule," Docket Nos. IS05-82-000, *et al.* (March 6, 2006).

⁸ "Protest, Complaint, Motion to Intervene, Motion to Consolidate, and Request for Hearing and Other Relief of Anadarko Petroleum Corporation," Docket No. OR05-3-000 (Dec. 16, 2004).

Tesoro Corporation (Tesoro) subsequently intervened in both Anadarko's 2005 Protest and Complaint proceeding and the State's 2005 Protest and Complaint proceeding.⁹

6. On July 20, 2005, the TAPS Carriers filed a petition pursuant to section 13(4) of the ICA requesting the Commission to (1) investigate the 2005 intrastate rates imposed by the RCA, (2) find such intrastate rates to be unduly preferential and unjustly discriminatory against and an undue burden on interstate commerce, and (3) raise the 2005 intrastate rates to the level of the 2005 filed interstate rates.¹⁰

7. In December of 2005, the TAPS Carriers filed their interstate rates for 2006, which ranged from \$3.78 to \$4.41 per barrel, for the transportation of ANS crude oil from Pump Station No. 1 to Valdez. On December 14, 2005, Anadarko and Tesoro (along with its affiliate, Tesoro Alaska Company) (collectively, Anadarko/Tesoro) filed a joint protest and complaint of the TAPS Carriers' 2006 filed rates (Anadarko/Tesoro's 2006 Protest and Complaint), alleging that the 2006 rates were unjust, unreasonable, unduly discriminatory and otherwise unlawful.¹¹ On that same day, the State filed a protest of the TAPS Carriers' 2006 filed rates and a complaint with respect to the TAPS Carriers 2004 and 2005 filed rates (State's 2006 Protest and Complaint).

8. In its 2006 Protest and Complaint, the State alleged that the TAPS Carriers' 2006 filed rates (1) violated the unjust discrimination and undue preference provisions of sections 2 and 3(1) of the ICA, (2) were inconsistent with the terms of the Interstate Settlement Agreement, (3) improperly included intrastate litigation costs, and (4) impermissibly included imprudently incurred costs for the Strategic Reconfiguration Program. The State subsequently withdrew the portion of its 2006 Protest and Complaint dealing with item (3),¹² and on September 15, 2006, the Chief Judge severed the investigation of Strategic Reconfiguration Program costs (item (4)) from

⁹ "Motion to Intervene of Tesoro Petroleum Corporation," Docket Nos. IS05-82-000, *et al.* (Jan. 5, 2005).

¹⁰ "Petition of the TAPS Carriers for the Commission to Investigate and Set Intrastate Rates and Motion to Consolidate Proceedings," Docket No. OR05-10-000 (July 20, 2005).

¹¹ "Protest, Complaint, Motion to Intervene, Motion to Consolidate, and Request for Hearing and Other Relief of Anadarko Petroleum Corporation, Tesoro Corporation, and Tesoro Alaska Company," Docket No. OR06-2-000 (Dec. 14, 2005).

¹² See State's October 11, 2006 Notice.

this proceeding.¹³ Consequently, items (1) and (2) are the only portions of the State's 2006 Protest and Complaint that remain at issue in this phase of the proceeding.

9. Arctic Slope Regional Corporation, Flint Hills Resources Alaska, LLC (Flint Hills), Williams Alaska Petroleum, Inc. (Williams), Petro Star Inc. (Petro Star), ConocoPhillips Alaska, Inc., and the RCA each moved to intervene in one or more of the proceedings described above.¹⁴

10. Except to the extent that issues were withdrawn or severed, the foregoing protests and complaints and the TAPS Carriers' section 13(4) petition were consolidated and set for hearing.¹⁵ The parties filed direct (December 7, 2005), supplemental direct (with respect to the TAPS Carriers 2006 filed rates) (April 4, 2006), answering (May 26, 2006) and reply (August 11, 2006) rounds of prepared testimony on those remaining issues. The hearing commenced on October 31, 2006 and ended on January 11, 2007. Initial and reply briefs were filed on February 16, 2007 and March 21, 2007, respectively, by the TAPS Carriers, Commission Trial Staff (Staff), Anadarko/Tesoro, the State, the RCA, Flint Hills, and Petro Star.

III. ISSUES

ISSUE I: WHICH PARTIES BEAR THE BURDEN OF PROOF ON WHICH ISSUES?

Burden of Proof - Carriers' Filed Rate Increases and Anadarko/Tesoro's Protests and Complaints

¹³ *BP Pipelines (Alaska) Inc.*, 116 FERC ¶ 63,056 (2006).

¹⁴ See *State of Alaska*, 110 FERC ¶ 61,129 at P 5 (2005); *BP Pipelines (Alaska) Inc.*, 112 FERC ¶ 61,219 at P 3 (2005); "Notice of Intervention of the Regulatory Commission of Alaska," Docket No. OR05-10-000 (August 5, 2005); *State of Alaska*, 114 FERC ¶ 61,174 (2006) at P 4; *BP Pipelines (Alaska) Inc.*, 110 FERC ¶ 63,015 (2005); "Order of Chief Judge Granting Motion for Leave to Intervene," Docket Nos. IS05-82-000, *et al.* (Jan. 10, 2005); "Order of Chief Judge Granting Motions for Leave to Intervene," Docket Nos. IS05-82-000, *et al.* (Jan. 25, 2005); "Order Further Modifying Procedural Schedule and Granting Motions to Intervene," Docket Nos. IS05-82-000, *et al.* (Jan. 19, 2006).

¹⁵ See *BP Pipelines (Alaska) Inc.*, 109 FERC ¶ 61,376 (2004); *State of Alaska*, 110 FERC ¶ 61,129; *BP Pipelines (Alaska) Inc.*, 112 FERC ¶ 61,219; *State of Alaska*, 114 FERC ¶ 61,174.

11. The Carriers, Anadarko/Tesoro, and Staff all agree that the Carriers bear the burden of proof with regard to the Carriers' filed rate increases for 2005 and 2006 under ICA section 15(7), 49 U.S.C. app. 15(7) (1994). The Carriers claim that Anadarko/Tesoro's protests and complaints propose that the TSM should no longer be used and that the Carriers be required to file one rate. Thus, the Carriers assert that this is a third party challenge to an existing rate, and accordingly, Anadarko/Tesoro bear the burden of proving that the existing rate is unlawful. With respect to Anadarko/Tesoro's proposal to adopt a different methodology for establishing interstate rate ceilings, the Carriers state that Anadarko/Tesoro bear the burden of proving both that the TSM is unreasonable and that Anadarko/Tesoro's proposed new rates are reasonable.¹⁶ In sum, the Carriers claim that Anadarko/Tesoro, as the parties proposing a new methodology for establishing interstate rates, bear the burden of proving: (1) that the TSM is unjust and unreasonable and (2) the proposed replacement methodology is just and reasonable.

12. Staff and Anadarko/Tesoro state that it is the Carriers, and not Anadarko/Tesoro, that bear the burden of proving the TSM produces just and reasonable rates. Staff claims that the Carriers' argument that the burden of proving the unlawfulness of the existing rate and the reasonableness of a replacement rate rests with Anadarko/Tesoro, is incorrect. This is evident, Staff and Anadarko/Tesoro contend, because the Commission, in accepting the settlement did not find, and has never found, the TSA or the TSM it established just and reasonable.

13. Anadarko/Tesoro and Staff also argue that the Carriers' suggestion that they have no burden of proof as to unchanged components of their rates is also incorrect. Both Anadarko/Tesoro and Staff cite *Northern Border Pipeline Co.*, 89 FERC ¶ 61,185 at 61,574 (1999) (*Northern Border*) and *Williston Basin Interstate Pipeline Co.*, 107 FERC ¶ 61,164 at P 21-26 (2004) (*Williston Basin*), for the proposition that the Carriers' bear the burden of proof with respect to each element of the TSM. Moreover, Anadarko/Tesoro and Staff state that since each item in the pipeline's proposed cost of service is part of the proposed rate increase, the Carriers' ICA section 15(7) burden includes the burden of supporting the dollar amount of each item in the cost of service, including any unchanged items. Staff further argues that to the extent the Carriers fail to show the justness and reasonableness of their rates, the Commission may order refunds of the overall increase in the cost of service. Last, Anadarko/Tesoro state that they, as the complainants, carry the burden of supporting their complaints which they claim they have fully satisfied.¹⁷

¹⁶ Carriers' IB at 14-15 (citing *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 186-87 (D.C. Cir. 1986) (*Sea Robin*) for the proposition that a third party proposing to change a methodology bears the burden of proof).

¹⁷ Anadarko/Tesoro IB at 11 (citing *Tesoro Refining and Mktg. v. Frontier*

14. The Carriers response states that they disagree with Anadarko/Tesoro's and Staff's contention that the Carriers bear the burden of proving that the TSM is just and reasonable. In fact, the Carriers contend, their burden only requires the Carriers to justify their filed rates as just and reasonable.

Discussion/Findings

15. The Carriers 2005 and 2006 filings propose rate increases. Accordingly, as discussed more in depth below, the findings with respect to this issue are as follows: (1) the Carriers bear the burden of proving that the TSM produces just and reasonable rates, and effectively, that the Carriers' proposed rate increases for 2005 and 2006 are just and reasonable and (2) Anadarko/Tesoro, as the complainants bear the burden of proof with respect to their complaints.¹⁸ Anadarko/Tesoro and Staff are in agreement, and the Carriers concede, that section 15(7) of the ICA and the Commission in *Trans Alaska Pipeline Sys.*, 35 FERC ¶ 61,425 at 61,983 n.17 (1986), placed the burden of showing the proposed increases in the 2005 and 2006 rates are just and reasonable upon the Carriers.¹⁹

16. The only point of contention with regard to this issue concerns the Carriers' claim that because they have not proposed to change the TSM, Anadarko/Tesoro bear the burden of proving that the TSM, as an existing methodology, is unjust and unreasonable. Carriers IB at 14. As discussed by Anadarko/Tesoro and Staff, *Williston Basin* and *Northern Border* stand for the proposition that a pipeline proposing a change in its overall cost of service must justify each element in the new cost of service including the unchanged elements. In *Williston Basin*, the Commission stated that "[s]ince each item in the pipeline's proposed cost of service is a part of the pipeline's proposed rate increase, the pipelines' [NGA] section 4 burden to support the proposed general rate increase includes the burden of supporting the dollar amount of each item in the cost of service, including unchanged items."²⁰

Pipeline Co., 105 FERC ¶ 61,227 at P 24 (2003)).

¹⁸ *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 107 FERC ¶ 61,175 at P 150 (2004) ("In any complaint filed before the Commission, the complainant carries the burden of proof regarding the facts and law asserted.").

¹⁹ The Commission, in approving the TSA, held that the Carriers' annual TSM tariff filings (like the ones at issue here) would be treated as "any rate change filing under the ICA," with the "burden of proof...upon the carrier to show that the proposed changed rate...is just and reasonable....". 35 FERC at 61,983 n.17.

²⁰ 107 FERC at P 24. Staff, the Carriers, and Petro Star agree that Sections 4 and 5 of the NGA are equivalent to the Section 15(7) and 15(1) of the ICA. Carriers

Thus, for the Carriers, this means proving that both the changed and unchanged cost of service elements, and effectively, the TSM itself and its derived rates, result in just and reasonable rates. Accordingly, since the Carriers have proposed an increase in their rates, it is found that the Commission requires the Carriers to justify each element of the proposed rates. This is confirmed by the Commission's pronouncements in adopting the TSA. To wit, the Commission stated that "the burden of showing that the new rate is just and reasonable will be on the TAPS Carriers, pursuant to section 15(7) of the ICA which provides that in any 'hearing involving a change in rate... the burden of proof shall be upon the carrier to show that the proposed changed rate... is just and reasonable. The carriers cannot rely on the approved settlements to establish the justness of these filed rate changes, since the settlement rates were never adjudicated to be just and reasonable.'" 35 FERC at 61,977 n.17.

17. The burden of proof with respect to the Carriers' section 13(4) petition and the State's section 2 and 3(1) claims will be addressed in the appropriate sections below.

ISSUE II: SHOULD THE TAPS SETTLEMENT METHODOLOGY BE USED TO DETERMINE TAPS RATES?

Issue II. A. Scope of the Issue

18. The TAPS Carriers argue that the Commission limited the scope of the hearing to the issue of whether the TAPS Carriers' filed rates comply with the TSM and did not include the issue of whether the TSM should continue to be the governing methodology for TAPS. Determinations by the Commission that the TSM is binding on all parties to the TAPS rate proceedings, the Commission's decision not to apply a different ratemaking methodology to TAPS, and the narrow scope of the issues in this proceeding show that the Commission views TAPS rates that comply with the TSM as lawful, the Carriers claim. Since the Commission's orders approving the TSA in 1985 and 1986, the Carriers aver, the Commission has affirmed that TSM is the ratemaking methodology that governs TAPS rates on several occasions. Specifically, the Carriers state that the Commission's original orders approving the TSM in *Trans Alaska Pipeline Sys.*, 33 FERC ¶ 61,064 (1985); 35 FERC ¶ 61,425 (1986), state that the TSM would not be binding on non-settling parties. However, the Carriers assert that the Commission's position on the TSM evolved following the enactment of the

IB at 106; Staff RB at 4; PS RB at 4 n.3. Section 5 of the NGA is equivalent to Section 15(1) of the ICA and Section 4 of the NGA is the equivalent of 15(7) of the ICA. Carriers' IB at 106; PS RB at 4 n.3; *Texaco Refining and Marketing Inc. v. SFPP, L.P.*, 117 FERC ¶61,285 at 61,367 (2006) (*Sepulveda*).

Energy Policy Act of 1992 (EPAAct of 1992). Evidence of this evolution, the Carriers contend, can be found in *Amerada Hess* where the Commission found that “[t]he TSM is now binding on the TAPS Carriers, all parties to TAPS rate proceedings, as well as the Commission” and “[t]he TAPS Carriers may not establish rates on any other basis.” Carriers RB at 12 (citing *Amerada Hess Pipeline Corp.*, 79 FERC ¶ 61,300, 62,358 (1997) (emphasis omitted) (*Amerada Hess*)).

19. In addition, the Carriers claim that in Order No. 561 the Commission followed the directive of Congress to exclude TAPS from the methodological reforms implemented in Title 18 of the EPAAct.²¹ In Order No. 561, the TAPS Carriers assert, the Commission required TAPS rates to be justified in accordance with the TSM and stated that the TSM would control if a conflict were to arise between the TSM and the revisions in Order No. 561. The Carriers further claim that Commission Order No. 588 states that the Carriers could continue to file rates based on the TSM and would only need to file rates pursuant to *Williams Pipe Line Co.*, 21 FERC ¶ 61,260 (1982) (Opinion 154) if their filings sought to charge rates under the Opinion 154-B methodology.²² The positions taken by Anadarko/Tesoro and Staff are groundless, the Carriers claim. In conclusion, the Carriers state that the sole issue to be resolved is whether the TAPS Carriers’ 2005 and 2006 filed rates comply with the TSM.

20. In contrast, Anadarko/Tesoro assert that the scope of this issue is defined by the protests and complaints that the Commission set for hearing. Anadarko/Tesoro state that their protests and complaints raised issues regarding whether the TSM and TSM derived rates are just and reasonable, and if such rates are not, how to develop just and reasonable cost-based rates for TAPS. The complaints and protests did not raise TSM compliance issues, Anadarko/Tesoro contend. Moreover, Anadarko/Tesoro argue, the scope is not limited to compliance with the TSM since the Commission in, *Trans Alaska Pipeline Sys.*, 35 FERC at 61,983 n.17, and the United States Court of Appeals for the District of Columbia (D.C. Circuit) in, *Arctic Slope Reg’l Corp. v. FERC*, 832 F.2d 158, 163 (D.C. Cir. 1987), held that the Carriers cannot rely on the TSM to establish the justness and reasonableness of their rates. Anadarko/Tesoro also state that when the Carriers submitted the TSA for approval they requested a ruling that it was in the public interest, not just and reasonable. Staff agrees with Anadarko/Tesoro’s claims that the scope of the issue is not limited to whether the Carriers properly followed the TSM formula and that the scope of the issue is defined in the protests and complaints. According to Staff, the Commission

²¹ Carriers IB at 16 (citing Order No. 561, *Revisions to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992*, FERC Stats & Regs. ¶ 30,985 at 30,961(1993) (Order No. 561)).

²² Carriers IB at 16 (citing Order No. 588, *Oil Pipeline Cost-of-Service Filing Requirements*, FERC Stats & Regs. ¶ 31,037 at 30,053 (1996) (Order No. 588)).

was clear, when it accepted the TSA, that challenges to the annual TSM rate filings would be allowed by non-signatories such as Anadarko/Tesoro and such rates would be judged under the just and reasonable standard.

21. Next, Anadarko/Tesoro and Staff aver that the TSM has not “evolved” as the Carriers contend, into a just and reasonable rate methodology that cannot be challenged by non-signatory parties. Specifically, Anadarko/Tesoro and Staff argue that the Carriers’ claims that the Commission later reversed the holdings concerning the rights of non-signatory parties to challenge future rates and that the TSM has been adjudicated as just and reasonable rely primarily on *Amerada Hess*. Anadarko/Tesoro and Staff assert that *Amerada Hess*, is distinguishable because the issue in that case was limited to TSM compliance and, consequently, neither the justness and reasonableness of the TSM nor the shipper’s rights to challenge the TSM were before the Commission.²³

22. Moreover, Anadarko/Tesoro and Staff contend, the Carriers use of the statement that the TSM is “binding on...all parties” is taken out of context. Anadarko/Tesoro claim that the Commission was simply stating that for compliance purposes it could not order a change in the TSM retroactively and issues related to refunds had to be decided in accordance with the TSM. Thus, Anadarko/Tesoro and Staff conclude, nothing in *Amerada Hess* limited the statutory right of shippers to challenge future TSM filings under the ICA or suggested that the Commission intended to change its prior orders and deem the TSM just and reasonable.

Discussion/Findings

23. The scope of this proceeding is defined by the Commission’s orders setting the issues in Anadarko/Tesoro’s and the State’s protests and complaints for hearing.²⁴ The Commission’s language in each of the orders is virtually identical. In each order, the Commission described Anadarko/Tesoro’s protests and complaints as arguing that

²³ Anadarko/Tesoro and Staff state that the issue in *Amerada Hess* was strictly an accounting question. Staff states that the Commission examined whether certain oil spill costs were properly recorded in Account No. 610 or 680 of the Commission’s Uniform System of Accounts for Oil Pipelines. The Commission also examined whether the TSM excludes amounts recorded in Account 680 from the definition of operating expenses to be recovered.

²⁴ *BP Pipelines (Alaska) Inc.*, 109 FERC ¶ 61,376 (2004) (protests to 2005 rates); *State of Alaska v. BP Pipelines (Alaska) Inc.*, 110 FERC 61,129 (2005) (complaints to 2005 rates); *BP Pipelines (Alaska) Inc.*, 113 FERC 61,332 (2005) (protests to 2006 rates); *State of Alaska v. BP Pipelines (Alaska) Inc.*, 114 FERC 61,174 (2006) (complaints to 2006 rates).

“the TSM does not produce rates that are just and reasonable under” the ICA. Then, the Commission, again in each order, established hearing procedures to examine the issues raised in the protests and complaints.²⁵ The Commission was clear that the issues raised by Anadarko/Tesoro, as well as the State, were to be the subject of the consolidated hearings. Thus, it is found that the scope of this proceeding, *inter alia*, includes the TSM calculated 2005 and 2006 rates as well as the TSM itself.

24. The Carriers claim that the Commission’s orders defined the scope of the hearing as follows: “the issues of this case pertain to application of the TSM to the TAPS 2005 Tariffs. The parties have different understandings of how the terms of the TSM apply when there is an order from the RCA that may be inconsistent with the TSM.”²⁶ This language does not indicate that the Commission intended to narrow the scope of the hearing. The Commission described the issues contained in Anadarko/Tesoro’s protests and complaints, but never stated that it would not allow Anadarko/Tesoro’s TSM arguments to be addressed, in their entirety, at the hearing. Consequently, it is found that the scope of the issues in the protests and complaints are significantly broader than those listed in the sentences cited by the Carriers. Limiting the scope as suggested by the Carriers would mean removing the main contention from Anadarko/Tesoro’s protests and complaints – that the TSM itself results in rates that are not just and reasonable. It would be remiss to ignore the main arguments in Anadarko/Tesoro’s protests and complaints especially in light of the fact that the Commission ordered that such arguments be considered.

25. The Carriers also contend that the Commission’s perspective that the TSM would not be binding on non-settling parties has evolved, the TSM governs TAPS rates and the Carriers may not establish rates on any other basis, and the TSM is now binding on all parties. Carriers’ IB at 16, RB at 11. As articulated by Anadarko/Tesoro, the gist of the Carriers’ argument is that the “TSM has ‘evolved’ such that it now binds even non-settling parties and is thus immune to challenge under

²⁵ *BP Pipelines (Alaska) Inc.*, 109 FERC ¶ 61,376 at P 10; *State of Alaska v. BP Pipelines (Alaska) Inc.*, 110 FERC ¶ 61,129 at P 3; *BP Pipelines (Alaska) Inc.*, 113 FERC ¶ 61,332 at P 20-21; *State of Alaska v. BP Pipelines (Alaska) Inc.*, 114 FERC ¶ 61,174 at P 16-17.

²⁶ Carriers’ IB at 17 (citing *BP Pipelines (Alaska) Inc.* 109 FERC ¶ 61,376 at P 10; see also *State of Alaska v. BP Pipelines (Alaska) Inc.*, 110 FERC ¶ 61,129 at P 3; *BP Pipelines (Alaska) Inc.*, 113 FERC ¶ 61,332; *State of Alaska v. BP Pipelines (Alaska) Inc.*, 114 FERC ¶ 61,174. In addition, the Carriers argue that the Commission also limited the scope by stating that the suspension order “benefits customers by ensuring that the rates for transporting petroleum on TAPS are consistent with the settlement.” Carriers’ IB at 17 (citing *BP Pipelines (Alaska) Inc.*, 109 FERC ¶ 61,376 at P 2).

the 'just and reasonable' standard." A/T RB at 11. Anadarko/Tesoro and Staff focus their rebuttal on the Carriers use of *Amerada Hess* to support the Carriers' position that the TSM is "now binding on... all parties." Carriers IB at 16, RB at 11-12, 16 (citing *Amerada Hess*, 79 FERC at 62,538).

26. Not even a cursory review of *Amerada Hess* would support the Carriers' contentions. See *Amerada Hess*, 79 FERC ¶ 61,300. This is because the Carriers' arguments rely on two sentences in the *Amerada Hess* order without placing them in the proper context. *Id.* Anadarko/Tesoro's and Staff's assertions that the issue in *Amerada Hess* was an accounting question limited to TSM compliance and that issues concerning the justness and reasonableness of the TSM were not before the Commission, however, are clearly supported by the text of the order. *Id.*; A/T RB at 12; Staff RB at 8-9. Moreover, Anadarko/Tesoro's and Staff's arguments that the Commission's statement that the TSM is now binding on all parties only referred to: (1) TSM compliance and (2) the Commission's decision that the Carriers were obligated to determine the refunds and address accounting issues consistent with the TSM are persuasive. A/T RB at 12; Staff RB at 8-9.

27. Contrary to the Carriers' assertions, the EPAAct of 1992, Order Nos. 561, 561-A and 588, do not indicate an evolution in the Commission's previous determinations. Carriers' IB at 16 n.15. In fact, those pronouncements are congruent with previous orders concerning the TSA. The language in the Commission's orders approving the TSA indicate that the Commission intended the TSM to govern TAPS unless or until a challenge was filed by a non-signatory. The Carriers fail to cite any language in these EPAAct of 1992 pronouncements that limits the rights of non-signatory parties. In conclusion, as discussed above, nothing cited by the Carriers indicates that the Commission changed its position with respect to the legal status of the TSM as articulated in *Trans Alaska Pipeline, Sys.*, 35 FERC ¶ 61,425²⁷ and *Arctic Slope Reg'l Corp. v. FERC*, 832 F.2d 158²⁸. Importantly, it is found that the statement that "the

²⁷ *Trans Alaska Pipeline System*, 35 FERC ¶ 61,425 at 61,977 n.17 ("The [C]arriers cannot rely on the approved settlements to establish the justness of these filed rate changes, since the settlement rates were never adjudicated to be just and reasonable.") *Id.* at 61,981 ("we categorically state that our approval of this settlement is not a precedent as to future TAPs' rates"). *Id.* at 61,980 ("We affirm the conclusion of the ALJ that the settlement may not be imposed on any objecting party, including Arctic."). *Id.* at 61,982 ("Arctic, as well as any entity which is not a party to the settlement, may file at any time in the future for an adjudicated rate, which does not exceed the settlement rate...")

²⁸ *Arctic Slope Reg'l Corp. v. FERC*, 832 F.2d 158 at 161 ("Under the TSM,... rates are set on an annual basis, and are regarded under the regulatory schemes as any other rate filings by a common carrier. Thus, any such rates are subject to challenge

Carriers cannot rely on the approved settlements to establish the justness of... filed rate changes" remains intact and has not been reversed by the Commission. See *Trans Alaska Pipeline System*, 35 FERC ¶ 61,425 at 61,978 n.17.

Issue II. B. What Legal/Regulatory Principles Apply?

Just and Reasonable Rate Standards

28. Anadarko/Tesoro's assertion that the TSM cannot be used to determine the justness and reasonableness of the 2005 and 2006 rates since the TSM includes elements that are not cost-based is incorrect, the Carriers claim. The Carriers state that the TSM, although non-traditional, is a cost-based methodology. In addition, the Carriers claim that if it is determined that the TSM elements are not cost-based, the TSM could still be found to be in compliance with *Farmers Union Central Exchange, Inc., v. FERC*, 734 F.2d 1486 (D.C. Cir. 1984) ("*Farmers Union II*"), which stated that departures from a cost-based approach may be legitimate if each deviation is found to be not unreasonable and consistent with the public interest. Accordingly, the TAPS Carriers conclude, the Commission would be justified in utilizing the TSM to determine the lawfulness of the TAPS interstate rates.

29. Next, Carriers again argue that the Commission's determination in *Amerada Hess* that the TSM is "now binding... on all parties" does not conflict with previous Commission orders approving the TSA which stated that non-settling parties would not be bound by TSM at that time. Carriers IB at 19; *Amerada Hess*, 79 FERC ¶ 61,300. In fact, the Carriers argue that the principle that future rate challenges must be brought pursuant to Opinion 154-B without relying on components of the TSM supports the Commission's findings in *Amerada Hess* that the TSM is "now binding... on all parties." *Amerada Hess*, 79 FERC ¶ 61,300. By the mid-1990's, the Carriers claim, rates calculated under the Opinion 154-B methodology (without use of TSM elements) would be greater than the TSM ceiling rates, and for that reason, the Commission was justified in concluding that the TSM was the only meaningful constraint on the TAPS Carriers' rates and that TSM is binding on all parties. The Carriers again claim that the legal status of TSM evolved after the enactment of EPAAct of 1992.

by non-settling parties, such as Arctic, as well as any other non-signatory." *Id.* at 166 n.16 ("FERC has explicitly stated... that its settlement approval in no way establishes the justness or reasonableness of any rates" and that "the agency was not even considering, much less near the point of decision on, the reasonableness of the TSM and the rates established under it".)

30. Anadarko/Tesoro and Staff state that the applicable standards for determining just and reasonable rates are set forth in *Farmers Union II* and Opinion 154-B.²⁹ Anadarko/Tesoro and Staff further assert that a just and reasonable rate is one that is cost-based with any departures specifically identified and justified as articulated in *Farmers Union II*, 734 F.2d at 1530, and Opinion 154-B.³⁰ The Commission adopted trended original cost (TOC) for determining rate bases and revenue requirements for oil pipelines in Opinion 154-B, Anadarko/Tesoro also state.

31. Staff similarly argues that although the TSM may contain some elements of a cost-based methodology, it is clear that the TSM also contains elements that are not appropriate for a cost-based rate.³¹ In addition, Staff and Anadarko/Tesoro assert that the Carriers did not submit any evidence to support their TSM rates on a cost basis and even failed to discuss the justness and reasonableness of the TSM by eliminating section II.D from their briefs. Staff's reply brief also argues that the Carriers cite *Farmers Union II* to support the contention that non-cost factors can be considered, but fail to note that its application is limited. Specifically, Staff claims that *Farmer's Union II* states that deviations from cost-based pricing must be found not unreasonable and the resulting rate must be justified by those factors.

32. Anadarko/Tesoro and Staff claim that the Carriers concede that the TSM does not comply with just and reasonable rate standards. Specifically, Anadarko/Tesoro assert that: (1) the Carriers and their expert, Dr. Toof concede that the TSM is inconsistent with just and reasonable rate standards and cannot be approved outside the context of an uncontested settlement; (2) Dr. Toof acknowledged that ABP is not tied to the Carriers' costs; and (3) Dr. Toof agreed that neither the TSM true-up

²⁹ In addition, Anadarko/Tesoro contend that the applicable regulatory principles are those for setting the just and reasonable rates under the ICA, which include Sections 1(5) and 15(1) of the ICA. Section 1(5), Anadarko/Tesoro claim, requires all interstate rates charged for oil transportation to be just and reasonable and Section 15(1) requires the FERC to prescribe a just and reasonable rate if it finds a rate unjust or unreasonable or unjustly discriminatory.

³⁰ Anadarko/Tesoro claim that in *Williams Pipe Line Co.*, 21 FERC ¶ 61,260 (1982) (Opinion 154), the Commission issued a decision attempting to justify the retention of the ICC's "valuation" approach to ratemaking for oil pipelines. The Carriers state that Opinion 154 was rejected in *Farmers Union II* and in response, the Commission issued 154-B adopting an original cost rate method for oil pipelines.

³¹ Staff states that the cost-based elements of the TSM include depreciation, DR&R, amortization of the \$450 million rate base write-off, and deferred earnings. Some of the non-cost-based elements included in the TSM, Staff contends, are the inflation-adjusted, non-cost based APB, a 100% equity structure assumption, and a depreciable life known to be too short.

provision nor the method of allocating costs between federal and state jurisdictions is acceptable for use in making just-and-reasonable rate determinations. Thus, Anadarko/Tesoro contend, the Carriers agree that the TSM is incompatible with just and reasonable ratemaking standards.

Equitable Estoppel

33. The Carriers also argue that under the doctrine of equitable estoppel, Anadarko/Tesoro after waiting 20 years to challenge the justness and reasonableness of TSM interstate rates and reaping the benefits of the TSA, should not be allowed to invalidate the TSM. This late challenge regarding purported overcollections, the Carriers claim, also raises serious concerns about retroactive ratemaking. Anadarko/Tesoro's failure to challenge the rates over the years further supports the Commission's conclusion in *Amerada Hess* that the TSM is now binding on all parties, the Carriers contend. In addition, the Carriers state that the Commission should reaffirm its earlier finding that the TSM is binding on all parties and that rates that do not exceed the TSM rate ceilings are lawful. A ruling to that effect, the Carriers claim, would avoid many intergenerational equity issues, enhance prospects for building future infrastructure investments in Alaska and elsewhere, and would be appropriate since the TSA could be terminated in less than two years.³²

34. Anadarko/Tesoro respond by arguing that they are not equitably estopped from challenging the filed rates because their right to challenge those rates is guaranteed by the Commission, the court orders approving the Interstate Settlement, and the ICA itself. In addition, Anadarko/Tesoro assert that they timely filed protests and complaints to the Carriers' 2005 and 2006 rates and the Commission recognized their standing to do so in setting the protests and complaints for hearing. Nothing cited by the Carriers alters these rights, Anadarko/Tesoro contend. Specifically, Anadarko/Tesoro assert, the case law on equitable estoppel requires, *inter alia*, false representation, reliance, and unjust enrichment involving a party to the agreement. None of those elements are present here, Anadarko/Tesoro claim.

35. Anadarko/Tesoro also aver that the Carriers' equitable estoppel argument fails because contrary to the Carriers' assertion that Anadarko/Tesoro have benefited from the TSA for more than 20 years without challenging the rates, Anadarko/Tesoro have only began producing oil on the North Slope in 2000 and have actually been paying excessive rates on TAPS since then. Staff's reply also states that the Carrier's

³² The Carriers state that "[O]n January 1, 2007, the State exercised its right under Section I-8 of the TSA to commence negotiations regarding the replacement of TSM. If such negotiations are not successful the State can terminate the TSA as early as January 1, 2009." Carriers IB at 24 n.25 (citing Ex. ATC-14 at 11; FHR-55).

equitable estoppel and retroactive ratemaking arguments are without merit. With regard to equitable estoppel, Staff similarly argues that the Commission's orders approving the TSA guaranteed the shippers the right to seek just and reasonable rates under the ICA and that right was never waived. Staff claims that the retroactive ratemaking argument is moot because Anadarko/Tesoro have not requested any remedies prior to the date the rates in this proceeding were suspended, subject to refund.

Public Interest

36. Third, the TAPS Carriers argue that they have shown that the public interest supports a holding that the 2005 and 2006 rates are in compliance with the TSM. The public interest, the Carriers state, must be considered by the Commission in adjudicating the lawfulness of the Carriers filed rates and has been found, by the Supreme Court and other courts, to be a key factor in judging the lawfulness of rates under the ICA.³³ The public need for investors in energy infrastructure projects to make necessary investments and the public need for efficient investment in and long-term development of energy resources support upholding the TSM, the Carriers claim. In their reply brief, the Carriers further assert that a Commission decision rejecting the TSM would have a chilling effect on future investment.

37. In response, Anadarko/Tesoro aver that their initial brief shows that the Carriers have misused the public interest standard. It is the just and reasonable standard that is applicable here, Anadarko/Tesoro contend. Moreover, Anadarko/Tesoro claim that the Carriers incorrectly stated that Anadarko/Tesoro's position is that public interest considerations are irrelevant to a determination of whether the TSM-based filed rates are just and reasonable. Anadarko/Tesoro state that this is contrary to their position and what Anadarko/Tesoro actually assert is that the public interest is met by setting just and reasonable rates and providing adequate incentives for investment while protecting shippers from excessive rates. Thus, Anadarko/Tesoro claim, their position is consistent with the case law concerning the public interest cited by the Carriers. Staff also states that setting just and reasonable

³³ In support of the proposition that the public interest should be considered in determining just and reasonable rates, the Carriers cite the Supreme Court in *Midstate Horticultural Co., Inc., v. Pennsylvania R.R.*, 320 U.S. 356 (1943) and *ICC v. Cincinnati, N.O. & T.P. Ry.*, 167 U.S. 479 (1897). Carriers IB at 23 n.22. The Carriers' reply brief also cites *Farmers Union II* in arguing that the D.C. Circuit recognized that the Commission could and should take the public interest into consideration and did not foreclose departing from a "rigid cost-based approach to ratemaking."

rates is in the public interest and should give investors comfort since it allows the recovery of costs and a fair rate of return.

38. Flint Hills argues that the TSA should be allowed to continue until it terminates under its own terms because the TSA will likely terminate at the end of 2008, and both the Commission and public policy require that the settlement be allowed to run its full course. First, Flint Hills states that the TSA has two mechanisms for termination: (1) section III-12 of the TSA, where the TSA would run its course and terminate at the end of 2011 and (2) section I-8, whereby a party can seek to renegotiate the agreement beginning January 1, 2007, and if the parties fail to renegotiate within two years of that date the State or any of the TAPS owners can give written notice terminating the TSA as early as December 31, 2008. The State sent a notice of renegotiation on January 1, 2007, Flint Hills claims. The benefit of allowing the TSA to run its course, Flint Hills contends, is that the controversy with respect to what has been collected under the TSM (for example, DR&R) would be eliminated.

39. Second, Flint Hills argues that the United States Supreme Court recognizes the importance of upholding settlements. FH IB (citing *United Gas Co. v. Mobile Gas Corp.*, 350 U.S. 332, 344 (1956)). The D.C. Circuit, Flint Hills asserts, has held that rate contracts should not be unilaterally modified unless required by the public interest and that the fact that a contractual rate may be higher than rates calculated under a different methodology does not necessarily trigger a public interest finding that the contract should be abrogated. Similarly, Flint Hills asserts that the federal courts do not favor allowing a party to undo a settlement that applies to others. Flint Hills also contends that the D.C. Circuit has also stated that the Commission has a preference to preserve the benefits of the parties' bargain in the contract. Moreover, Flint Hills adds, the State and Anadarko are not shippers on TAPS. Tesoro which does ship on TAPS, ships ANS petroleum which is not preferred by Tesoro at its Kenai Refinery in Alaska. In contrast, Flint Hills states that it and Petro Star fully support the continued use of the TSM and that significantly, they are refiners that can only run ANS petroleum and must ship all their refineries' crude on TAPS.

40. Third, Flint Hills claims that the Commission's policy is to allow settlements to run their full course since it provides the benefit of certainty. Flint Hills also argues that the Commission's decision in *Kern River Gas Transmission Corp.*, 117 FERC ¶ 61,077 (*Kern River*) (2006), upheld a long-term levelized rate structure which was the product of settlement to allow shippers to realize the benefits bargained for in the settlement. The Interstate TSA and TSM are producing levelized rates and lower rates in outer years just as the parties intended, Flint Hills contends. For these reasons, Flint Hills concludes that the TSA and TSM have achieved the public policy goals and should be found just and reasonable.

41. Flint Hills also argues that the settlement principles in *Kern River* should also apply to the TSA since the rate design is analogous to the levelized rate design used by Kern River. Flint Hills claims that the rate designs share a common thread which is a key to the Commission's holding in *Kern River*. According to Flint Hills, in both cases, the pipeline carrier assumes some risk with respect to an element in the rate design. For Kern River, the risk was any depreciation not recovered within the first 15 years and the Carriers' assumed risk is tied to the APB since the dollar amount collected depends on throughput volume, Flint Hills contends.³⁴ In conclusion, Flint Hills asserts that the Commission's statement in *Kern River* that it is inherent in any levelization plan that the levelized rate will remain in effect for the entire agreed upon period should also apply to the TSA due to the trade-offs that occurred during the TSA's formation. In response, Staff states that Flint Hills's argument that the APB represents deferred return and must be retained so that the Carriers receive the benefit of their bargain is without merit. The TSM contains a separate element for deferred return and it is not the APB, Staff contends. Moreover, Staff avers, the only bargain struck was between the State and the Carriers and it only prohibited the State from protesting rates under the TSM ceiling.

42. Flint Hills further claims that the State and Staff have not rebutted the Commission's policy of ensuring that settlements, particularly those with levelized rates, run their full term. The Commission's recent pronouncements in *Sepulveda*³⁵ and *Kern River* support allowing the TSA and TSM to run their full term, Flint Hills asserts. Moreover, Flint Hills claims that when the TSA was approved, it was known that the rates of return under the TSM, including the APB, could be higher than otherwise allowed.

Discussion/Findings

43. As discussed further, *infra*, *Farmers Union II* and Opinion 154-B are the applicable ratemaking standards. First, the Commission has already held that the TSM cannot be used to establish just and reasonable rates. Second, Anadarko/Tesoro are not equitably estopped from challenging the TSM or the filed rates. Third, the Carriers public interest arguments are rejected since the applicable ratemaking standards perform a balancing act that protect investors' rate of return expectations. Flint Hills' assertions that the TSA should be allowed to run its course are rejected.

³⁴ Flint Hills goes on to explain since the ABP was substituted for the original Rate of Return beginning in 1990, if actual throughput volumes prior to 1990 exceed projections, the Carriers would earn less than they would have earned had the switchover began before 1990.

³⁵ Flint Hills' arguments concerning *Sepulveda* are more appropriately discussed in Section III below.

44. As discussed above, section 15(7) requires the Carriers to prove that their 2005 and 2006 filed rates are just and reasonable. Anadarko/Tesoro, Staff, the Carriers, and Flint Hills agree that Opinion 154-B should be used to determine whether the rates filed by the Carriers are just and reasonable.³⁶ Thus, the applicable regulatory principles are stated in *Farmers Union II*, which provided guidance to the Commission on the factors to consider in formulating a rate making methodology, and the Commission's adoption of those guidelines in Opinion 154-B.³⁷ It is found that just and reasonable rates should be cost-based. See *Farmers Union II*, 734 F.2d 1486; Opinion 154-B, 31 FERC ¶ 61,377.

45. In seeking to define what the "just and reasonable" statutory requirement for ratemaking entails, the D.C. Circuit, in *Farmers Union II*, stated that "the statutory standard is, of course, not very precise." 734 F.2d at 1501. However, the Court went on to explain that as determined by "decades of judicial review of agency determinations of 'just and reasonable' rates: an agency may issue, and courts are without authority to invalidate, rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'" *Id.* at 1502. *Farmers Union II* also noted that the "zone of reasonableness" strikes a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable. *Id.* Finally, the court offered, "[b]ecause the relevant costs, including the cost of capital, often offer the principal points of reference for whether the resulting rate is 'less than compensatory' or 'excessive,' the most useful and reliable starting point for rate regulation is an inquiry into costs." *Id.* The court also stated that "non-cost factors may legitimate a departure from a rigid cost-based approach" and may "play a legitimate role in the setting of just and reasonable rates," but such deviations must be justified. *Id.* at 1502-03.

46. In closing, the D.C. Circuit provided "important and basic guideposts" to assist the Commission in establishing an appropriate ratemaking methodology. Specifically, *Farmers Union II* stated the following: (1) oil pipeline rates must be set within the "zone of reasonableness" as required by the ICC (and presumed market forces may not comprise the principle regulatory constraint); (2) departures from cost-

³⁶ The Carriers' claim that the filed rates should be found just and reasonable if they comply with the TSM has been rejected as discussed in Section II.A, *supra*. In addition, the Commission has already made clear that the Carriers' cannot rely on the TSM to justify their rates. The Carriers and Flint Hills state that if TSM is not used to measure TAPS rates, then the appropriate methodology is set forth in Opinion 154-B. Carriers' IB at 19, FH RB at 18.

³⁷ Staff has provided a helpful summary of the history of *Farmers Union II* and Opinion 154-B in their brief. Staff IB at 11-14.

based rates must be made, if at all, only when the non-cost factors are clearly identified and the substitute or supplemental ratemaking methods ensure that the resulting rate levels are justified by those factors; (3) the rate of return methodology should account for the risks associated with the regulated enterprise; and (4) the choice of a proper rate of return is only part of an integrated ratemaking method, thus, the FERC must scrutinize the rate base and the rate of return methodologies to see that they will operate together to produce a just and reasonable rate. 734 F.2d at 1530.

47. Opinion 154-B was issued in response to *Farmers Union II*. Opinion 154-B rejected the valuation methodology as the model for calculating rate base, and revenue requirements, and replaced it with the TOC methodology. 31 FERC at 61,833. Opinion 154-B acknowledged the guidelines set forth in *Farmers Union II*, including the “guideposts” stating that oil pipeline’s rates must be set within the “zone of reasonableness” and that departures from cost-based rates must be clearly identified. *Id.* at 61,832 (citing *Farmers Union II*, 734 F.2d at 1530). It also announced that “[i]t is evident that oil pipeline rates as a general rule must be cost-based.” *Id.* at 61,833. The methods for determining, *inter alia*, the rate of return, rate base, and a starting rate base were also established in Opinion 154-B. Accordingly, it will be the “guideposts” set forth in *Farmers Union II* and Opinion 154-B, and not the TSM, that shall be used as the regulatory framework for determining whether the TSM and the 2005 and 2006 rates it produced are just and reasonable.

48. The Commission and the D.C. Circuit have already stated that the Carriers cannot rely on the TSA, and accordingly, the TSM to establish the justness and reasonableness of its filed rates.³⁸ As articulated by the D.C. Circuit, “FERC has explicitly stated... that its settlement approval in no way establishes the justness or reasonableness of any rates.” *Arctic Slope*, 832 F.2d at 166; *see Sohio Pipe Line Co.*, 35 FERC at 61,982. The Carriers correctly note that *Farmers Union II* allows departures from a “rigid cost-based approach,” but “each deviation... must be found not to be unreasonable and to be consistent with the Commission’s statutory responsibility” to serve the public interest. Carriers’ IB at 19 (citing 734 F.2d at 1502). Thus, the elements of the TSM that depart from cost-based standards must be justified and only then can it be determined whether the TSM as a whole is just and reasonable.³⁹ It would be remiss not to perform a “reasoned inquiry” into such deviations and rely only upon a Commission approved settlement which the Commission itself stated is of no precedential value. *See Farmers Union II*, 734 F.2d

³⁸ The Carriers argument that they properly applied the TSM in calculating their filed rates is also rejected on the same grounds.

³⁹ This argument will be addressed in the following section where it will be determined whether the TSM comports with Opinion 154-B.

1502. Thus, it is *Farmers Union II* and Opinion 154-B that will serve as the standards for this inquiry and the Carriers' argument that the TSM should be used to determine just and reasonable TAPS rates is rejected.

49. Second, with regard to the Carriers' equitable estoppel arguments, Anadarko/Tesoro and Staff aptly note that the Commission's order approving the TSA preserved the rights of "Arctic, as well as any entity which is not a party to the settlement," to file "at any time in the future for an adjudicated rate, which does not exceed the settlement rate." *Trans Alaska Pipeline Sys.*, 35 FERC ¶ 61,425 at 61,982. In addition, the D.C. Circuit recognized that under the TSM, "rates are set on an annual basis, and are regarded under the regulatory scheme as any other rate filings by a common carrier... [t]hus, any such rates are subject to challenge by non-settling parties." *Arctic Slope Regional Corp.*, 832 F.2d 158 at 160. The time to challenge the Carriers' rates did not begin to toll from the moment the TSA was approved more than 20 years ago as the Carriers seemingly contend. Each yearly filing brings a new opportunity for a non-signatory, such as Anadarko/Tesoro, to challenge the justness and reasonableness of the rates. This was the Commission's intent when it approved that TSA and that intent was confirmed when Anadarko/Tesoro's and the State's protests and complaints were set for hearing. Finally, the Carriers' contentions concerning retroactive ratemaking are rejected, as Staff recognizes, since Anadarko/Tesoro's requested remedies only concern the 2005 and 2006 rate filings which the Commission accepted, subject to refund.⁴⁰

50. Third, the public interest standard is not the standard that is applied in establishing just and reasonable rates; however, it is a key factor in such a determination. The Carriers contention that upholding the TSA is in the public interest is primarily based on financial factors. Specifically, the Carriers argue that the TSA should be upheld to preserve the sanctity of long term settlements and commitments regarding future rates and returns. Carriers RB at 14-15. Otherwise, the Carriers claim, investors in energy infrastructure projects will not make the necessary investments and there will be a "chilling effect on future investment." *Id.*

51. *Farmers Union II* states that the public interest should be taken into consideration, and to that end, the D.C. Circuit contemplated setting rates within the "zone of reasonableness." 734 F.2d at 1502. The D.C. Circuit stated that this zone would strike a fair balance between the financial interests of the regulated company

⁴⁰ *BP Pipelines (Alaska) Inc.*, 109 FERC ¶ 61,376 at P 2; 113 FERC ¶ 61,332 at P 3. See *Oxy USA, Inc. v. FERC*, 64 F.3d 679 at 699 (D.C. Cir 1995) (the rule against retroactive ratemaking in Section 15(7) procedures is not violated where all parties are placed on notice that the agency has the authority to order a refund of any part of the increase that it finds to be unjustified).

(in this case the Carriers) and the relevant public interests, both existing and foreseeable. *Id.* (citations omitted). The "zone of reasonableness" also requires rates that are neither "less than compensatory" nor "excessive." *Id.* Again, the D.C. Circuit has taken the relevant financial interests of investors into consideration and established, in its guideposts to the Commission, a ratemaking framework that will compensate investors and ensure that such investors still receive a reasonable return on their investment.⁴¹ Anadarko/Tesoro witness John F. Brown stated that "the Commission allows pipelines an opportunity to recover... a return of, and reasonable return on, the remaining investment in the pipeline. Thus, just and reasonable rates appropriately balance the pipeline's interest in maintaining service and attracting capital with the shipper's interest in paying rates that are not excessive." AT-78 at 6, 13 (citing *Farmers Union II*, 734 F.2d at 1502); A/T IB at 17 n.9.

52. More succinctly stated, "just and reasonable rates consider both pipeline and shipper interests." AT-78 at 13 (John Brown). The Carriers rely on Professor Joseph P. Kalt's testimony for the proposition that maintaining TSM will serve the public interest and investors will not make necessary investments if regulators do not preserve commitments regarding future rates and returns, and allow opportunistic conduct once the investment is made. Carriers IB at 22-23, RB at 14-15. However, the Carriers omit the portion of Professor Kalt's testimony that states that such concerns can be alleviated "through the consistent, proper application of an integrated ratemaking methodology, such as Opinion 154-B." ATC-4 at 38-40.⁴² Establishing just and reasonable rates does not undermine the spirit of the TSA or the expectations of investors since the relevant regulatory principles ensure that the Carriers will still recover a fair return on their investment. Any expectation to receive more than that is contrary to Commission precedent.

53. In addition, the orders approving the settlement left the door open for non-signatories to challenge the rates established by the settlement, even if such rates are below the ceiling rate. *Arctic Slope*, 832 F.2d at 161; A/T-78 at 15. Signatories and investors were placed on notice that the TSM requires rates to be set on an annual basis and such rates, and the TSM itself, are subject to challenge by non-signatories.

⁴¹ *Farmers Union II* at 1502 (quoting *City of Chicago v. FPC*, 458 F.2d at 731, 750-51 (D.C. Cir. 1971) ("When the inquiry is on whether the rate is reasonable to a producer, the underlying focus of concern is on the question of whether it is *high* enough to both maintain the producer's credit and attract capital. To do this, it must, *inter alia*, yield to equity owners a return commensurate with returns on investments in other enterprises having corresponding risks.")).

⁴² ATC-4 at 38-39. It is noted that Professor Kalt also states that "the more efficient outcome is to continue to abide by and support settlements, like the TAPS Settlement Agreement and TSM." ATC-4 at 39.

See Arctic Slope, 265 U.S. at 161. Moreover, setting rates within the “zone of reasonableness” as required by Opinion 154-B will establish just and reasonable rates for non-signatory shippers while allowing investors to continue to recover a reasonable return on their investment in TAPS. The sanctity of a long term settlement must be weighed against the risk of allowing unjust and unreasonable rates to continue.⁴³ Similarly, the Carriers’ argument that by the mid-1990s rates calculated under Opinion 154-B exceeded TSM rates and that the TSM has kept rates below just and reasonable Opinion 154-B calculated rates does not automatically render the TSM or the TSM calculated rates just and reasonable. This will be further discussed in section III below.

54. Flint Hills fails to recognize that the Commission approved the TSA with a caveat – non-signatories are free to challenge the TSA and the rates it establishes using the TSM. *See Trans Alaska Pipeline Sys.*, 35 FERC ¶ 61,425 at 61,980-982. The fact that the remaining life of the TSA is now less than two years is not sufficient to (1) strip the rights of non-signatories to challenge filed rates as granted by the Commission and (2) allow the TSA to continue, in the face of such a challenge, when the Commission itself has stated that the TSA has not been shown to produce just and reasonable rates. Moreover, Flint Hills’ arguments that the TSM has produced lower rates than projected, the State and Staff previously supported the approval of the TSM without a time limitation, and it was known that there was a possibility that TSM rates would be higher in the future fail with respect to Anadarko/Tesoro’s challenge to the rates for the same reasons. FH RB 6-14, 17-18. Flint Hills cites *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 (2006) (*Kern River*), for the proposition that the TSM must run its course to achieve the agreed upon levelized rates. The Commission allowed non-signatories to step forward and challenge the TSA, and accordingly, the TSA derived rates can only be allowed to run its course if the Carriers prove that the TSM results in just and reasonable rates. *See Arctic Slope*, 832 F.2d at 166 (the FERC had not considered the reasonableness of TSM and the rates established under it). Flint Hills is now requesting that the Commission impose the TSA on a non-signatory such as Anadarko/Tesoro, which is something the Commission has already declined to do. FH IB at 11; *See Trans Alaska Pipeline Sys.*, 35 FERC at 61,980-982.

55. In conclusion, the applicable ratemaking standards are set forth in *Farmers Union II* and Opinion 154-B. The Carriers arguments concerning equitable estoppel,

⁴³ As noted by the D.C. Circuit, FERC “was not even considering, much less near the point of decision on, the reasonableness of the TSM and the rates established under it.” The Commission has also stated that the “Carriers cannot rely on the approved settlements to establish the justness of these filed rates changes, since the settlement rates were never adjudicated to be just and reasonable.”

retroactive ratemaking, and the public interest are rejected. Flint Hills' arguments are also rejected. It is noted that the Commission does favor upholding the sanctity of settlements. However, with respect to the TSA, the Commission has explicitly stated that it did not enforce the terms of the TSA on non-signatories such as Anadarko/Tesoro.⁴⁴ For that reason, the arguments that the TSA should be allowed to terminate under its own terms and be upheld, solely on public interest grounds, are rejected.

Issue II. C. Have the Applicable Standards been Satisfied?

56. The Carriers aver that because the TSM is binding on all parties and the Carriers 2005 and 2006 rates comply with the TSM, the rates are lawful. The Carriers state that they have shown that they properly applied the TSM in calculating their filed rates by presenting the testimony of Dr. Toof, who concluded that the filed rates were equal or less than the TSM ceiling rates. The State did not present evidence directly responding to Dr. Toof's showing and Anadarko/Tesoro failed to dispute this showing as well, the Carriers contend.

57. The Carriers claim that by showing their filed rates are lower than rates calculated using the 154-B methodology, the Carriers have met their burden.⁴⁵ The Carriers also claim that the Commission's regulations in 18 C.F.R. part 342, allow an oil pipeline to defend its rates on an Opinion 154-B basis even if the rates were negotiated or settlement rates. In addition, the Carriers cite *Magellan Pipeline Co.*, 105 FERC ¶ 61,390 (2003), for the proposition that a pipeline can submit a cost-of-service defense of the rate once it has been challenged in a valid protest. The Carriers claim that the rates can be defended by showing that the challenged rate is lower than the rate the pipeline could otherwise lawfully charge. Carriers' IB at 27 (citing *Sithe/Independence Power Partner, L.P. v. FERC*, 165 F.3d 944, 951 (D.C. Cir. 1999); *ARCO Pipe Line Co.*, 41 FERC ¶ 63,015 at 65,081, *aff'd*, 41 FERC ¶ 61,397 (1987).

58. Anadarko/Tesoro and Staff claim that the Carriers fail to address this central issue in the initial and reply briefs. Anadarko/Tesoro argue that the Carriers have failed to satisfy the applicable legal standards in *Farmers Union II* and Opinion 154-B in two respects. First, Anadarko/Tesoro state that the Carriers incorrectly apply the less rigorous "public interest" standard which governs uncontested settlements,

⁴⁴ This addresses Flint Hills' arguments concerning its assertion that the Commission's policy is to allow settlements to run their full course. FH IB 12-21; RB 9-12.

⁴⁵ The Carriers discuss this in Section III of their reply brief; however, this discussion is more appropriately addressed here. Carriers RB at 27-28.

instead of the "just and reasonable" standard which governs rate proceedings and is applicable here. Anadarko/Tesoro also argue that when the Commission approves a settlement as being in "the public interest," the Commission does not make an independent finding that the settlement rates are "just and reasonable."

59. Second, Anadarko/Tesoro assert that the Carriers also failed to satisfy the legal standards because the Carriers did not provide any evidence that the TSM rate formula or the filed TSM rates reflect the Carriers' actual cost of providing service. Anadarko/Tesoro argue that the Commission has held that, with respect to formula rates, the formula is the rate and the formula itself must meet the just and reasonable standard. As a result, Anadarko/Tesoro claim that the Carriers must justify the TSM formula and its components and not just a specific rate level to satisfy the just and reasonable standard. Instead, Anadarko/Tesoro contend, the Carriers present two proxy cases that have nothing to do with the Carriers' cost of providing service. The Carriers present a SAC proxy based on hypothetical costs and an Opinion 154-B proxy based on a different methodology with different inputs, and consequently, Anadarko/Tesoro argue, both proxies fail to show the cost of providing service on TAPS and should be rejected.

60. Next, Anadarko/Tesoro argue that the "end result" test is incorrectly used by the Carriers. Anadarko/Tesoro contend that the Commission has held that the test is employed after the Commission has approved the specific elements of the rate and the Carriers are not relieved of the burden of proving the specific rate elements. Anadarko/Tesoro also claim that the Carriers use the "end result" test for the proposition that the Carriers do not have to consider the TSM rate elements, but only the final rate. Finally, Anadarko/Tesoro argue that the Commission in *Olympic Pipeline Co.*, 101 FERC ¶ 61,245 at P 17 (2002), held that in a rate hearing, a pipeline must support the rate case it originally filed and not a different case later developed at the hearing which created a "moving target."

61. Staff posits arguments similar to Anadarko/Tesoro's. Specifically, Staff states that the Carriers failed to submit cost information to support the elements of the TSM formula that make up their filed rates. The Carriers cannot simply rely on their argument that mechanical compliance with the TSM formula or public interest concerns establish the justness and reasonableness of their rates. Staff claims. Staff also states that the Carriers argument that demonstrating that the filed rates were all equal to or less than the TSM ceiling rates does not satisfy the standard. The Carriers' 154-B proxy, Staff avers, uses "costs" that fail to recognize the large amounts of depreciation, DR&R, deferred earnings, and amortization already collected through rates. In fact, Staff contends, only Anadarko/Tesoro and the State provide Opinion 154-B presentations that accurately calculate the TAPS cost of service. Staff claims that the Carriers' application of the SAC presentation is unprecedented at the

Commission and is irrelevant. Accordingly, Staff concludes, the Carriers have not satisfied the applicable standards and the rates should be rejected.

Discussion/Findings

62. It has already been determined that the applicable ratemaking standards in *Farmers Union II* and Opinion 154-B require rates generally to be cost-based. More importantly, the relevant precedent mandates that each component of the cost of service be supported. See *Williston Basin*, 107 FERC at P 24. The Carriers bear the burden of proving that the TSM and the rates it produces are just and reasonable. As discussed above, this necessarily requires the Carriers to provide cost justification for each element of the TSM. This burden is not met by the Carriers' showing via Dr. Toof's testimony, or otherwise, that the 2005 and 2006 rates comply with the TSM. Nor can the burden be met by the Carriers use of hypothetical Opinion 154-B and SAC proxies to assert that the TSM ceiling rates produce lower, and therefore, just and reasonable rates.

63. The TSM cost elements and supporting justification must stand on their own. The Carriers have failed to provide cost data to support the elements of the TSM, and accordingly, the Carriers have not met their burden of proving that the TSM is just and reasonable. The Carriers' argument that Anadarko/Tesoro and the State failed to respond to Dr. Toof's testimony showing that the Carriers filed rates were equal or less than the TSM ceiling rates is irrelevant. It is the Carriers that have the burden of proving the TSM is just and reasonable and Dr. Toof's presentation did not satisfy this burden. Moreover, to the extent that the TSM contains elements that depart from a cost-based approach, such deviations must be shown not to be "unreasonable and ...consistent with the Commission's statutory responsibility." See *Farmers Union II*, 734 F.2d at 1502. Since the Carriers have not provided any supporting cost data to support their filed rates, they failed to meet their burden of proof.

64. The case law cited by the Carriers does not support the proposition that an Opinion 154-B proxy can be used to meet their burden of proof concerning the costs of providing service under the TSM. Carriers' IB at 27 (citing *Sithe/Independence Power Partner, L.P.*, 165 F.3d at 951).⁴⁶ Staff correctly states that such use of an

⁴⁶ For instance, *City of Holyoke v. FERC*, involved a comparison of a transmission rate *vis-a-vis* the integrated transmission rate, which is not the issue in the case at bar. *City of Holyoke Gas & Elec. Dep't v. FERC*, 954 F.2d 740 (D.C. Cir 1992). *Magellan Pipeline Company, L.L.C.*, involved a rate filing set for hearing. 105 FERC ¶ 61,390 (2003). *Sithe/Independence Power Partners, L.P., v. FERC*, in dicta talks about "end results" and comparing the rate charged to the rate that could legally be charged (citing the *City of Holyoke, supra*) in the discussion about rolled-in or incremental methodologies. 165 F.3d 944 (1999). These cases clearly do not

Opinion 154-B proxy “must be used in conjunction with the inputs that made up the filed rate. Otherwise, you have proven nothing, and certainly not the justness and reasonableness of the filed rate.” *Id.* As discussed in more detail below, the inputs used by the Carriers’ in their 154-B proxy, would allow an enormous double recovery of costs and do not reflect the actual balances. Moreover, Anadarko/Tesoro appropriately point out that the Carriers use the “end result” test incorrectly. A/T IB at 19 n.10 (citing *So. Co. Svcs., Inc.*, 80 FERC P 61,318 at 62,089 n.64 (1997)). “[T]he ‘end result’ test does not relieve Southern of the burden of supporting the specific elements of its rate, but is, instead, an additional test to which the rate is subject after the Commission has approved those specific elements.” *So. Co. Svcs., Inc.*, 80 FERC at 62,089 n.64 (citing *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168, 1177-78 (D.C. Cir. 1987)). Thus, the Carriers cannot just rely on the “end result” test – they must still prove each element of the TSM to meet their burden.

65. Anadarko/Tesoro’s arguments addressing the Carriers’ public interest arguments have been discussed above.

Issue II. D. Are the rates determined by the TSM just and reasonable?

66. The Carriers claim that the TSM methodology taken as a whole is cost-based.⁴⁷ According to the Carriers, Anadarko/Tesoro and Staff argue that the Carriers’ failure to provide cost justification for specific elements of TSM means that the Carriers’ filed rates are not just and reasonable. The Carriers claim that this argument is not sustainable since the TSM was not designed to be evaluated on an element-by-element basis. This is evidenced by statements made by the State and the U.S. Department of Justice (DOJ) in the Explanatory Statement submitted as part of the TSA, the Carriers assert. In sum, the Carriers contend that the statements provide that the elements of the TSM were drawn from general ratemaking principles and should not be evaluated independently since the elements were negotiated as a package tailored for TAPS to meet the objectives of the parties.

67. The Carriers also argue that the fact that the individual elements of TSM may not be justified on a cost basis does not mean that TSM or the ceilings it calculates are not cost-based. It is noteworthy, the Carriers assert, that the State and the DOJ compared TSM generated rates to rates generated by the ICC valuation methodology, a DOC methodology, and a TOC methodology and found that the TSM ceiling rates were at or below the other traditional methodologies. The Carriers contend that this

parallel the facts in this case.

⁴⁷ This argument also includes the Carriers’ contentions that the TSM is cost-based in Section II.B above.

confirms the TSM's reasonableness. In addition, the Carriers claim that there is also no merit to Anadarko/Tesoro's contention that the Carriers must justify the TSM formula itself as just and reasonable. According to the Carriers, this is because the TSM is not part of the Carriers' filed tariffs.

68. Anadarko/Tesoro and Staff posit extensive arguments that the Carriers have not shown that the TSM or the 2005 and 2006 rates are just and reasonable. The TSM includes non-cost based elements and the Carriers have failed to provide any direct evidence that shows the elements that comprise the TSM are just and reasonable, Anadarko/Tesoro and Staff contend. Specifically, Anadarko/Tesoro and Staff point to the following items and allege that the elements are not cost based or are inappropriate for cost-based ratemaking:

- (1) The inflation-adjusted, non-cost-based allowance per barrel (ABP).
- (2) The one hundred percent (100%) equity capital structure assumption.
- (3) The subjective projections of costs and throughput.
- (4) The depreciable useful life of the line that is known to be too short.⁴⁸
- (5) The true-up mechanism that guarantees cost recovery.
- (6) The cost allocation/rate design mechanism that allows costs properly allocated to intrastate rates, but disallowed by the RCA, to be reallocated to the interstate rates.
- (7) The DR&R collections premised on incorrect assumptions

Staff IB at 18-27, RB at 16; Anadarko/Tesoro IB at 20-34, RB at 22-26. Additionally, Anadarko/Tesoro claim that these elements are not cost-based and as a result of being included in the TSM: (1) produce excessive returns, (2) include excessive deferred returns, (3) include an excessive income tax allowance, and (4) include an unjustified DR&R allowance.

69. Staff again claims that the Carriers' have offered no cost evidence to support the TSM rates or any of the elements within the TSM. According to Staff, the closest the Carriers come to addressing whether the TSM produces just and reasonable rates is the Carriers' discussion of mechanical compliance, the public interest, equitable estoppel, and retroactive ratemaking. However, Staff contends, the Carriers fail to discuss just and reasonable or cost-based ratemaking standards. Similarly, Anadarko/Tesoro argue that the TSM produces rates that are inherently unjust and unreasonable and inconsistent with cost-based ratemaking standards. Anadarko/Tesoro also claim that the Carriers and Flint Hills failed to address issue II.D. Thus, Anadarko/Tesoro and Staff state, because there is no record evidence to

⁴⁸ Anadarko/Tesoro argue that this causes depreciation expense to be overstated.

demonstrate that that "costs" included in the filed rates represent the costs of service for TAPS and because the TSM violates just and reasonable ratemaking standards, the TSM cannot be used to determine just and reasonable rates.

Discussion/Findings

70. A discussion of the specific elements that Staff and Anadarko/Tesoro state are not cost-based is better left to section III where each of the items will be examined in detail *seriatim*. Although the Carriers have chosen not to follow the prescribed issues list format, it seems that the Carriers did include a discussion of whether rates determined by TSM are just and reasonable. In short, the Carriers argue that: (1) the TSM is a cost-based methodology and even if individual elements are not found to be cost-based, *Farmer's Union II* allows certain cost deviations; (2) the Commission found, in *Amerada Hess*, 79 FERC ¶ 61,300, that the TSM is binding on all parties; (3) Anadarko/Tesoro are equitably estopped from challenging the TSM; (4) Anadarko/Tesoro's challenge of the 2005 and 2006 filed rates raises concerns regarding retroactive ratemaking; (5) it is in the public interest to find the Carriers rates and the TSM just and reasonable; and (6) the Carriers have shown that they properly applied TSM in calculating their filed rates. All of these arguments have been rejected in the preceding sections of this decision.⁴⁹ One of the most important of these findings with respect to this issue is that the Carriers must submit evidence to support a finding that each element of the TSM is either cost-based or that the deviation from costs is justified. Staff and Anadarko/Tesoro aptly note that the Carriers' failed to place cost data to support the elements in the TSM in the record of this proceeding. As discussed above, without such evidence, the Carriers fail to meet their burden of proving the TSM and the rates it produces are just and reasonable. Accordingly, the rates determined by the TSM cannot be found just and reasonable.

Issue II. E. Do the TAPS Carriers' 2005 and 2006 TAPS Interstate Rates Comply with the TAPS Settlement Agreement?

71. Staff and Anadarko/Tesoro take no position on this issue. To the extent that the Carriers and Flint Hills assert a position, such arguments have been addressed above. As stated above, the mechanical compliance with the TSA does not, by itself, prove anything in this case, so this is a moot point.

⁴⁹ Anadarko/Tesoro's and Staff's arguments have already been considered with respect to these arguments.

ISSUE III: IF TSM SHOULD NOT BE USED, WHAT METHODOLOGY SHOULD BE USED AND HOW SHOULD THAT METHODOLOGY BE APPLIED?

Issue III. A. What is the Appropriate Methodology?

72. The Carriers state that if the TSM is not accepted as the governing methodology for determining the lawfulness of the Carriers' 2005 and 2006 rates, then Opinion 154-B and the Commission's cost of service regulations in, 18 C.F.R., part 346 (2006) apply. Since the parties agree that 154-B is the appropriate methodology, the large difference in the rates advocated by the parties, the Carriers contend, is due to the differences in the inputs each party uses in the formula. The Carriers state that their Opinion 154-B presentation uses the actual costs as recorded in their FERC Form 6 (Form 6) annual reports. Anadarko/Tesoro cannot "cherry pick" the most favorable terms of the TSM to use as inputs in their Opinion 154-B presentation, the Carriers claim. The Carriers also argue that no element of the TSA was to have any effect on the rights of non-settling parties and the non-setting parties have an all or nothing choice in litigating their rate challenge.

73. The Carriers argue that Anadarko/Tesoro's and Staff's attempt to apply *SFPP-Sepulveda*, 117 FERC ¶ 61,285 (2006) (*Sepulveda*), to this proceeding is unavailing because none of the fundamental underpinnings of the *Sepulveda* decision apply here. The Carriers assert that *Sepulveda* differs from the facts of this case because the contracts were between SFPP and the complaining shippers, the contract provisions did not limit the rights of third parties to rely on the contracts, and the Commission found that the contracts were fully performed on both sides.

74. Anadarko/Tesoro also state that although the parties agree that Opinion 154-B results in just and reasonable rates, there is a dispute concerning how to properly apply Opinion 154-B. Anadarko/Tesoro assert that just and reasonable rates should be established under either the TOC or DOC original cost rate methods. The Carriers' Opinion 154-B case is flawed because the Carriers do not use their actual costs as inputs, Anadarko/Tesoro contend. Anadarko/Tesoro claim that the Carriers have dramatically increased their total revenue requirement (TRR) by "restating and double counting their accumulated depreciation and deferred earnings, and by including a starting rate base adjustment." A/T IB at 40. Finally, Anadarko/Tesoro assert that the proxy cases presented by the Carriers have nothing to do with the Carriers' filed rates and fail to recognize 30 years of accelerated recovery of investment, deferred earnings, and DR&R.

75. Staff states that the appropriate methodology to use in setting TAPS rates is the TOC which is consistent with Opinion 154-B and *Farmers Union II*. Staff also claims that using either an Opinion 154-B TOC approach or the traditional DOC

approach as calculated by the State and Anadarko/Tesoro uses the proper inputs and are also similar to the DOC rate calculated by the RCA in its extensive proceeding. Staff concludes by stating that neither of the Carriers' proxies (SAC or Opinion 154-B) can be used to set rates or prove the justness and reasonableness of the Carriers' rates.

76. Proper application of the DOC and TOC methodologies, Anadarko/Tesoro and Staff claim, requires the inputs to reflect amounts actually collected by the Carriers. Staff contends that only the interstate rates calculated by the State and Anadarko/Tesoro are consistent with the Carriers' previous rate filings and the revenues already collected by the Carriers. The Carriers' Opinion 154-B proxy has nothing to do with the costs reflected in the Carriers' rate filings, Staff avers. In addition, Staff contends that in using an Opinion 154-B methodology to determine an oil pipeline rate, the inputs that made up the filed rate must be used.

77. The Carriers' argument that Anadarko/Tesoro are "cherry picking" elements of the TSM is incorrect, Anadarko/Tesoro claim. Anadarko/Tesoro state that their reliance on the annual rate filings has nothing to do with attempting to enforce rights under the TSA since Anadarko/Tesoro are simply including the current property balances from the Carriers' rate filings. Contrary to the Carriers' assertions, Staff also claims, using the actual recoveries does not constitute "cherry picking" from the TSA by Anadarko/Tesoro. Staff states that this argument fails for two reasons. First, Staff claims that the issue is not about enforcing the TSA, but the right of shippers to have just and reasonable rates in accordance with Commission policy and practice. Anadarko/Tesoro are simply accepting the balances as they find them and, Staff states, are not proposing to restate or alter these balances. Second, Staff claims that Anadarko/Tesoro are not selectively enforcing portions of the TSA because the bargain was only between the State and the Carriers and simply provided that the State would not protest or object to a maximum rate that complied with the TSM.

78. Staff claims that the numerous arguments forwarded by the Carriers to attempt to justify double recovery are without merit. Staff states that Commission precedent does not permit double recovery of investment. Staff also points to several reasons why *Sepulveda*, 117 FERC 61,285, applies to this proceeding and stands for the proposition that the Carriers' previous recoveries must be recognized for ratemaking purposes. Anadarko/Tesoro also assert that the Commission's decision in *Sepulveda*, which required SFPP to recognize prior recovery of investment in future rates is applicable here. *Id.* In addition, Staff avers that the Commission's decision in *Sepulveda* is consistent with its other rulings. Staff states that in *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 (2006), which involved the continued use of a levelized rate, the Commission required Kern River to create a regulatory asset to reflect the difference between what is reflected in its accounting books and what it collected in rates. The Commission confirmed that the regulatory asset is

recognized as an adjustment to the rate base, Staff contends. In addition, Staff claims that *Entergy Services, Inc.*, also stands for the proposition that allowing an investment to be recovered a second time is not just and reasonable.⁵⁰

79 The Carriers' reliance on accounting regulations to justify the use of Form 6 information is misplaced since ratemaking books must be used when there are differences between the ratemaking books and regulatory accounting books, Anadarko/Tesoro and Staff argue. Moreover, Anadarko/Tesoro and Staff state, Commission and court precedent are clear that when this difference occurs, ratemaking standards control and ratemaking balances must be used.

80. Flint Hills claims that the Carriers, and not the State and Anadarko/Tesoro have submitted proper Opinion 154-B presentations. According to Flint Hills, the rate methodologies submitted by Anadarko/Tesoro and the State are skewed and result in unreasonable rates because they omit the return elements deferred under the TSM. Anadarko/Tesoro's inclusion of the accelerated recovery items and the omission of the back-end deferred return items is the only way Anadarko/Tesoro was able to calculate a \$2 per barrel rate range. In conclusion, Flint Hills claims that the TSM rates are lower than the Carriers' properly calculated 154-B methodology rates and are therefore just and reasonable. If either Anadarko/Tesoro's or the State's Opinion 154-B presentations are used, significant corrections need to be made, Flint Hills claims.

Discussion/Findings

81. Although the parties agree that Opinion 154-B is the appropriate methodology to employ in this proceeding, the consensus ends there. It is the discussion concerning which amounts are the proper inputs where the parties' opinions sharply diverge. The Carriers and Flint Hills are advocating the use of the Form 6 balances, while Anadarko/Tesoro and Staff fervently contend that the appropriate balances are in the Carriers' annual filings. Anadarko/Tesoro and Staff have proven that it is their arguments that should prevail.

82. First, the Carriers must recognize the amounts they have previously collected in rates. The cases cited by Staff and Anadarko/Tesoro are applicable. The Carriers' attempt to distinguish *Entergy Services* fails. Carriers' RB at 41 n.40. Contrary to the Carriers' assertions, Staff cited *Entergy Services* for the basic proposition that allowing costs to be recovered twice is not just and reasonable and that assertion is clearly supported by the text of the initial decision which was later approved by the

⁵⁰ *Entergy Services, Inc.*, 102 FERC ¶ 63,016 (2003); 105 FERC ¶ 61,319 (2003) (*Entergy Services*).

Commission.⁵¹ Anadarko/Tesoro and Staff cite *Sepulveda*, with respect to this issue, to assert that the Carriers must recognize the amount of investment previously recovered: (1) even if the amounts recovered are different from the amounts reflected in the Carriers' accounting books and records and (2) even if such records comply with the Commission's Uniform System of Accounts. A/T RB at 41-42; Staff RB at 33-34, IB at 35-39. Anadarko/Tesoro and Staff effectively refuted the Carriers' arguments in opposition on this point. *Id.*; Carriers IB at 53-55, RB at 40-42.

83. To wit, Anadarko/Tesoro and Staff specifically acknowledge the "fundamental underpinnings" that the Carriers use to contrast *Sepulveda* with this proceeding. Staff and Anadarko/Tesoro rebut the Carriers' arguments by stating that: (1) the fact that the contract was between the complaining parties is immaterial since what matters is that the money was already collected from the shippers, Staff RB at 34; (2) regardless of whether the settlement contracts have run their course, the Carriers cannot recover their investment twice;⁵² and (3) it is irrelevant whether the SFPP contracts denied third-party beneficiary rights since parties to a settlement cannot restrict a third party's rights when determining a just and reasonable rate, Staff RB at 34. Importantly, Staff also notes that in *Sepulveda* "the contract's intentions regarding the recovery of investment were not explicitly stated and had to be presumed," but that is not the case here "where the recovery pattern for plant investment was explicitly described in the TSM." Staff IB at 38-39. Finally, *Kern River* also stands for the proposition that the Commission's objective is to ensure that entities do not double recover their investment.⁵³ The Carriers' arguments are without merit on this point and are therefore rejected. Carriers RB at 41 n.41.

84. The Carriers claim that Anadarko/Tesoro's use of the TSM balances constitutes "cherry picking" from the TSA and should not be permitted. Carriers' IB at 34-45. As discussed above, the Commission will not allow an investment to be

⁵¹ See 105 FERC at P4; 102 FERC at 98-100 (the Commission affirmed the ALJ's decision "(1) requiring Entergy to develop its rates using the net non-levelized methodology" where the ALJ did not allow Entergy to switch to the gross plant levelized method because of the concern that it would allow Entergy to "recover some of the depreciation expense attributable to this equipment a second time, and the customers as a class will have to pay twice for use of these facilities. Clearly, this result would be unjust and unreasonable").

⁵² The Carriers' argument that it is improper to recognize the accelerated recovery of any investment until it has been recovered in its entirety under the TSA also fails. See *Sepulveda*, 117 FERC 61,285; Staff RB at 34; IB at 39 n.103; (the Commission disallowed any over-recovery in *Sepulveda* and there was no indication that it was contingent on the amount of the investment recovered); A/T RB at 42-43.

⁵³ Staff IB at 40; *Kern River*, 117 FERC at P 48.

recovered twice. To that end, the mission here is to ensure that the inputs used in the Opinion 154-B methodology reflect amounts already recovered. Therefore, Anadarko/Tesoro and Staff are correct. The use of the amounts in the Carriers' filings has nothing to do with Anadarko/Tesoro or Staff attempting to enforce rights or provisions of the TSA.⁵⁴ Nor are Anadarko/Tesoro combining approaches by using the balances contained in the Carriers' filings. The Carriers collected rates pursuant to the TSA/TSM and, therefore, it is the filings made pursuant to the TSA that provide the most accurate picture of the Carriers' current property balances. Witness Sullivan's testimony provides a persuasive and an accurate explanation on this point.

For the past, you look at what has been recovered in rates, and we know what has been recovered in rates, because [the Carriers'] made annual ICA filings under the interstate settlement agreement....

....
[The filings] were made based on the TAPS settlement methodology... but it clearly shows the rate recovery, the past period rate of recovery that [the Carriers have] been able to recover, and going forward, you have to take those plant balances into account in establishing just and reasonable original-cost ratemaking standards.

Tr. at 5282:1-16 (Sullivan). Finally, where accounting regulations or balances do not match ratemaking standards or balances, it is the ratemaking balances that control.⁵⁵ Mr. Sullivan's testimony on this point is given significant weight.⁵⁶

⁵⁴ With that said, the Carriers' arguments that the TSA is an inseparable package and the independent items were not intended to be relied upon by third parties, are rejected.

⁵⁵ Staff IB at 44-46; 46 n.127 (citing *Virginia State Corp. Comm'n v. FERC*, 468 F.3d 845, 847 (D.C. Cir. 2006) ("Petitioners' claim of a rate effect is belied by the proposition that '[a]ccounting practices are not controlling for ratemaking purposes'" (citation omitted)); *Consolidated Gas Supply Corp.*, 14 FERC P 61,029, 61,053-54 (1981) ("Accounting practices are not controlling for ratemaking purposes and deviations from normal accounting practices must be made where necessary to insure that rates established by the Commission are just and reasonable"); *Williston Basin Interstate Pipeline Co.*, 55 FERC at 62,008 ("the Commission has stated that accounting does not dictate ratemaking"); *Williston Basin*, 56 FERC at 61,104, 61,370 ("The Commission is not bound by accounting principles in determining whether proposed rates are just and reasonable"); A/T IB at 46 n.33 (citing *id.*); Tr. 1659-62 (Wetmore concedes at one point that ratemaking treatment should be used for just and reasonable rates).

⁵⁶ Conversely, the Carriers' witnesses' testimony concerning the Opinion 154-B analysis is not credible.

85. The crux of the matter is that the Carriers must recognize the previous recoveries of their investment, otherwise there will be an unjust and unreasonable double recovery. The Carriers have presented no fact in the case that calls for an opposite conclusion. The Carriers' theory that Opinion 154-B analysis has to start from the beginning of TAPS as if the TSA/TSM had never occurred, or that the revenues recovered until now cannot be considered is not given any weight. Furthermore, Staff's commonsensical argument that just and reasonable rates cannot result where *any* double recovery is allowed simply cannot be ignored. Staff IB at 39. Accordingly, it is found that the inputs into the Opinion 154-B presentation must reflect the actual amounts collected by the Carriers even if that means using amounts other than those found in Form 6. This is consistent with the Commission precedent which disallows the double recovery of investment. Moreover, this is not a small matter since the differences between Anadarko/Tesoro's and the Carriers' total revenue requirement is significant. Anadarko/Tesoro's revenue requirement is \$647.32 million while the Carriers' is \$1,751.18 million.⁵⁷ See Illustration No. 1 below. Anadarko/Tesoro's amounts from Illustration No. 1 below are the basis for the conclusions reached in this decision although the final numbers used by Anadarko/Tesoro may vary slightly based on findings elsewhere in this initial decision (i.e., ROE and income tax).

⁵⁷ The main differences are attributable to deferred earnings, SRB, and depreciation and various rate base items.

Illustration 1

Comparison of Anadarko/Tesoro's Revised 154-B
And TAPS Carriers' 154-B ProxyTotal 2006 Revenue Requirements and Rates
(\$Millions)

Line No.	Description	Revised A/T 154-B	TAPS Carriers 154-B
1	Operating Expenses*	\$559.65	\$559.65
2	Depreciation Expense	\$13.48	\$335.43
3	Amortization of Deferred Earnings	\$7.13	\$223.84
4	Amortization of AFUDC	\$0.86	\$11.63
5	DR&R Allowance	\$0.00	\$0.00
6	Return Allowance		
7	Return on Equity	\$30.58	\$281.62
8	Interest	<u>\$13.77</u>	<u>\$9.59</u>
9	Total Return Allowance	<u>\$44.34</u>	<u>\$291.21</u>
10	Income Tax Allowance	\$22.13	\$329.04
11	Non-Transportation Revenues	<u>(81.27)</u>	<u>50.38</u>
12	Total Revenue Requirement	<u>\$647.32</u>	<u>\$1,751.18</u>
13	Composite System Barrels (Millions)	326.795	326.795
14	Composite Rate (\$/Bbl)	\$1.98	\$5.36
15	Valdez Interstate Rate (\$/Bbl)	\$2.04	\$5.53

* Includes amortization of FERC rate case litigation costs and RUC rate case litigation costs

86. The parties' general arguments with respect to the proper Opinion 154-B inputs are better addressed in the individual sections where the parties contentions are more tailored.

Issue III. B. What is the Appropriate Rate Base?

Issue III.B.1. What are the appropriate property balances for original investment, additions, retirements, and accumulated depreciation?

87. The Carriers assert that the balances shown in Form 6 represent the Carriers' actual investment in TAPS. The Carriers contend that Mr. Van Hocke rejected Anadarko/Tesoro's exclusion of the \$450 million in carrier property as of 1976 and further stated that as non-settling parties, Anadarko/Tesoro have no basis to claim the benefit of the \$450 million exclusion. In addition, the Carriers contend that the \$450 million should be included in the rate base because the amortization was a component of the settlement package that "assuredly [did] *not* set any rates." Carriers' IB at 50 (citing *Arctic*, 832 F.2d at 164 n.12). The Carriers also claim that the "amortization" of the \$450 million was a product of the settlement negotiations and reflected an assumed recovery in early years. The Carriers assert that the reduction in refunds arguments forwarded by Anadarko/Tesoro and the State should be rejected because the TSA states that there would be no refunds from 1977 through 1981 and for the period 1982-1985. Nothing in the TSA or Commission's orders suggests that any amortization or exclusion of the \$450 million for that period is appropriate, the Carriers contend.

88. Anadarko/Tesoro and Staff state that the appropriate property balances for original investment, additions, and retirements are the balances reported in the Carriers' annual filings. In addition, Anadarko/Tesoro state that the amounts reported in the Form 6 original property balances advocated by the Carriers and the original property balances in the annual rate filings are virtually identical. The main difference, Anadarko/Tesoro claim, is \$450 million excluded from the TAPS rate base that was separately amortized and recovered in rates from 1978-1984 pursuant to the TSA. The property balances reflected in the TSM filings are consistent with the rates charges and the revenues actually collected, Staff contends. Staff also states that, contrary to the Carriers' assertions, if the Commission would have intended to ignore costs already recovered when it established just and reasonable rates, it would have explicitly said so and provided legal justification. In addition, Staff states that contrary to the Carriers' assertions, *Boston Edison Company*, 61 FERC ¶ 61,026 (1992), actually supports Anadarko/Tesoro's position because unlike the Carriers the company voluntarily gave up the right to collect certain expenses and the Commission held the company to that decision and would not allow recovery later.

89. With regard to accumulated depreciation, the Carriers claim that they have followed Opinion 154-B and the Commission's order approving the 1982 Depreciation Stipulation (Stipulation) by using the actual investment costs and actual straight-line depreciation recorded in their Form 6 annual reports. The Carriers claim that Form 6 represents the actual depreciation expense incurred in past years and the sum of those amounts is the proper accumulated depreciation balance. Until changed by further order of the Commission, the Carriers contend, the Stipulation is binding in any proceeding involving the TAPS Carriers' interstate tariff rates.

90. The Carriers present several reasons in support of rejecting Anadarko/Tesoro's use of the TSM balances. First, the Carriers assert that Anadarko/Tesoro, as third party non-signatories, have no legal rights under and cannot enforce the TSA. Second, the Carriers argue that the Commission's order in, *Arctic*, 832 F.2d 158, approving the TSM clearly supports the assertion that the TSA was meant neither to burden nor benefit non-settling parties. Third, the Carriers claim that contrary to Anadarko/Tesoro's claims, the TSA did not supercede the Stipulation. Fourth, the Carriers claim that Anadarko/Tesoro have no basis to rely on TSM for depreciation or other rate base elements because the depreciation factors differ from traditional FERC approved depreciation.

91. The appropriate balances for accumulated depreciation are reported in the Carriers' annual filings, Anadarko/Tesoro aver. According to Anadarko/Tesoro, the Carriers Opinion 154-B utilizes an accumulated depreciation figure that completely ignores the accelerated depreciation: (1) used to calculate refunds for 1977 through 1985 and (2) reported by the Carriers in rate filings from 1986 to present. Anadarko/Tesoro assert that the Carriers' failure to recognize this prior recovery artificially inflates the rate base in the Carriers' Opinion 154-B presentation by over \$481 million and will lead to the double recovery of investment. Anadarko/Tesoro state that the regulatory history of TAPS shows that the Carriers' recovery of investment was based on accelerated depreciation.⁵⁸

92. Anadarko/Tesoro state that the Carriers' claim that all parties are bound to the 1982 Depreciation Stipulation fails because several witnesses have confirmed that the 1982 Depreciation Stipulation was not used for setting rates on TAPS. Furthermore, Anadarko/Tesoro claim that the Stipulation was superceded by the TSM.

⁵⁸ Anadarko/Tesoro state seven major aspects of that regulatory history that demonstrate that the Carriers' recovery of investment was based on accelerated depreciation. A/T IB at 49-59. To wit, representations to FERC and the Alaska Public Utilities Commission (APUC); the Carriers reduced their refund obligation; rates included accelerated depreciation; Carrier internal communications; expert testimony; other motives, and the 1982 Stipulation was never used to set rates. A/T IB 49-58.

Anadarko/Tesoro further assert that the Carriers' argument that the TSA and the Stipulation were expected to remain in effect simultaneously (the TSA would apply to signatories and the 1982 Stipulation would apply to shippers) is impossible because no party to the TSA is a shipper and only shippers paid the TSA rates. Thus, Anadarko/Tesoro conclude, the Stipulation and the TSA could not remain in effect at the same time. In conclusion, Anadarko/Tesoro assert that the book balances of accumulated depreciation reported in Form 6 were not used to set rates and the use of those balances will result in double recovery by the Carriers.

93. Staff also states that the TSM rates filed and collected from the shippers reflected an accelerated depreciation factor. This is clear, Staff contends, because the Carriers' annual rate filings, the supporting data and sections of the TSA itself show the depreciation expense, accumulated depreciation, and unrecovered property balances underlying the rate calculations.⁵⁹ Staff claims that the Carriers argument that without an explicit order from the Commission, the Stipulation remains in effect is incorrect. Contrary to the Carriers' assertions, Staff states, the Commission's orders were clear that it was approving TSM depreciation and even the Carriers Reply Comments (on the offer of settlement for the TSA) acknowledge that was what they were seeking from the Commission's approval of the TSA. Staff also states that the TSA provided that the only stipulations that were to remain in effect were those consistent with the TSA.

94. The shippers on TAPS pay rates based on the accelerated depreciation factors in the TSM and not the straight-line factors in the Stipulation, Staff claims. Thus, Staff contends, the Carriers' assertion that the TSM factors are only relevant to the settling parties is clearly incorrect since it is the non-signatory shippers and not the settling parties who have paid TAPS rates. Staff also claims that the Stipulation was replaced by the TSA. According to Staff, the language in the Stipulation gave the Commission and the parties the authority to terminate the provisions and the Carriers recognized and advocated the adoption of the TSM depreciation schedule in place of the Stipulation. Staff also claims that the Commission's orders accepting the TSA approved of the new TSM depreciation methodology in place of the Stipulation.

⁵⁹ Staff states that Section II-5 and Exhibit F of the TSA show the annual depreciation expenses to be recovered in the TSM rates. Exhibit G to the TSA also shows accelerated depreciation. In addition, Staff states that the Commission's Order Approving Settlement, dated October 23, 1985 also acknowledged that accelerated depreciation is included in the TSM.

Discussion/Findings

95. The appropriate rate base is one derived following the Commission's Opinion 154-B analysis and conforms to original costs ratemaking standards. In this case, the rate base should reflect net depreciated original costs as reflected over the years in the Carriers' rate filings before this Commission for almost three decades.

96. The Carriers, Anadarko/Tesoro and the State filed testimony using the 154-B analysis used by the Commission in setting rates for oil pipelines. However, the Carriers position is that the inputs to an Opinion 154-B analysis should be based on Form 6 as opposed to what they filed to justify their rate filings. It is found that the appropriate property balances for original investment, additions, and retirements are contained in the Carriers' annual rate filings.⁶⁰ Anadarko/Tesoro's cost of service presentations use the property balances reported by the Carriers in their annual rate filings. Anadarko/Tesoro use the amounts collected from ratepayers by the Carriers. These figures are found in the Carriers' annual rate filings and supporting documents. Accordingly, Anadarko/Tesoro's witnesses testimony is given significant weight.⁶¹

97. The only major difference between the property balances in the Carriers' annual filings and Form 6 is \$450 million which was excluded from the total TAPS rate base and separately amortized from 1978 through 1984 through TSM. A/T IB at 44; RB at 45 n.32; Staff RB at 21. The \$450 million has already been fully recovered by the Carriers via amortization from 1978 through 1984 under the TSM.⁶² This

⁶⁰ The amounts for 2005 are as follows (in millions): Carrier Plant in Service - \$10,294.12, Additions - \$14.855, Net Retirements - \$0.796, Non-Depreciable Plant - 68.161, Ineligible Plant - 97.24. A/T IB at 44; Ex. A/T-144, WP-2 at 5, ln. 1, 2, 3, 11, and 17 ("Col. 2004"). The amounts for 2006 are as follows (in millions): Carrier Plant in Service - \$10,308.96, Additions - \$19.991, Net Retirements - \$0.000, Non-Depreciable Plant - 68.161, Ineligible Plant - 120.14. A/T IB at 44; Ex. A/T-146, WP-2 at 4, ln. 1, 2, 3, 11, and 17 ("Col. 2005").

⁶¹ The Carriers' testimony is not credible. As a matter of fact Mr. Van Hoecke previously testified in RCA docket P-97-4 explaining the difference between Form 6 and the annual rate filings. Exs. A/T-143 at 27-28, A/T 234 at 1-2. This testimony is inconsistent with his testimony in this hearing. In the cited proceeding he testified that the primary differences are: (1) \$450 million removed from TSM balances and amortized; (2) \$17 million in land treated separately by TSM-6 and (3) \$56 million of timing differences between property records and TSM-6. Ex. A/T-143 at 27-28.

⁶² Ex. A/T-33 at 10 (Section II-2(c)) (the TSA states that the TAPS investment base is reduced by \$450 million and that amount is amortized from the period 1978 through 1984); Ex. A/T-140 at 28-30; Ex. A/T-140 at 28 (Brown); Ex. A/T-196 at

amount was clearly excluded from rate base as stated in the TSA. Thus, since this amount was excluded and amortized by virtue of the TSA and the TSM and the rates were charged based on the TSM, it is found that this is the correct way to treat the rate base in a 154-B analysis, as Staff and Anadarko/Tesoro point out. If the \$450 million is added back into rate base this would result in double recovery of investment which is not allowed by the Commission. Carrier witness Van Hoecke and Ganz advanced similar arguments in a previous proceeding which were rejected by the Commission. To wit, in *Sepulveda*⁶³ the Commission did not allow a carry over of 1983 construction costs since it would result in over-recovery of investment and is inconsistent with the depreciation method SFPP used in previous contracts. The same reasoning is applicable here where the Carriers have invested \$11 billion since TAPS was placed in service and have collected \$58 billion in revenues while expending \$15 billion in operation and maintenance. Ex. A/T 233 at 1. The amounts actually recovered by the Carriers must be recognized to avoid double recovery. Commission principles and policy do not allow costs to be included in rates twice.⁶⁴ Thus, it is found that the \$450 million of original investment has been properly excluded from the Carriers' rate base.

98. The appropriate balances for accumulated depreciation are reflected in the net plant balance in the Carriers' annual rate filings.⁶⁵ Anadarko/Tesoro cost of service presentation uses these correct balances. The Carriers' varied arguments contesting the use of the amounts in their annual filings are without merit. Again, the point of this exercise is to determine what the Carriers' actually collected. Anadarko/Tesoro have shown that the Carriers never used the Stipulation to set rates on TAPS via several witnesses in this proceeding.⁶⁶ In fact, the witnesses have verified that it has been the TSM and not the Stipulation that has been used to set rates on TAPS. *Id.*

237-8; A/T RB at 45 n.32. The State gave up refunds and the Carriers reduced their refund liability by this settlement. See A/T Ex -181 at 28; 116-125.

⁶³ 117 FERC ¶ 61,285 at P 18 (2006).

⁶⁴ See, *Town of Norwood v. FPC*, 546 F. 2d 1036 (D. C. Cir 1976); *Entergy Services, Inc.*, 109 FERC ¶ 61095 at P 55 (2004); *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077 at PP 47-48 (2006).

⁶⁵ The amounts of accumulated depreciation are as follows (in millions): (1) for 2005 - \$59.777 as shown in Ex. A/T-144, WP2 at 5, ln.7 ("Col 2004") and (2) for 2006 - \$58.228 as shown in Ex. A/T-146, WP2 at 4, ln.7 ("Col 2005").

⁶⁶ Staff RB at 29. Tr. 2979-80 (Van Hoecke); Ex. A/T-196 at 234-26 (Dr. Horst), Tr. at 867 (Confidential) (Dr. Toof stated that rates were not calculated using the Stipulation); Tr. at 1666 (Wetmore, the Carriers' witness, also stated that he was not aware of the Stipulation being used to establish rates on TAPS); A/T IB at 55 (citing Ex. A/T-175 at 73 (witness Folmer who prepares the financial package that the

99. Additionally, further proof of the fact that the Carriers have recovered accelerated depreciation is the representations they made to the Commission recommending approval of the TSA. In the Explanatory statement the parties stated that if the TSA is approved accelerated depreciation will be recovered in rates. Ex. A/T-35 at 6, 33-32. Previously, in an APUC proceeding State witness Horst testified that the parties to the TSA used a unit of throughput depreciation schedule accelerated through multiplying throughput factors. Ex. A/T-180 at 7. Furthermore, in approving the TSA the Commission recognized that the depreciation schedule, based on an accelerated unit-of-production method, is fixed and heavily weighted towards the earlier years.⁶⁷

100. The evidence in this case also establishes that from 1977-1985 the revenue requirements and rates were calculated in the TSM-6. Ex. A/T-44 and A/T-155, line 163.⁶⁸ In the hearing proceeding in Docket No. P-86-2 Mr. Baden testified he reconciled actual property data with Form 6 reports and confirmed that the TSM had real numbers behind them. Ex. A/T-178 at 19-20. Dr. Horst's deposition indicates that TSM-6 was split in half with the first half showing the historic pre-1983 numbers which became TSM-6. The ending balances from TSM-6 are identical to the beginning balances in Ex. G of the TSA. Ex. A/T-196 at 222-223. The historic balances in TSM-6, including operating expenses were used to determine refunds for the years 1982-1985 and for the determination that no refunds would be allocated prior to 1982. Ex. A/T-196 at 231, ln 1-6 and 236, ln 7-16. The rates in TSM-6 for 1982-1985 match Ex. D-1 to the TSA. Ex. A/T-33.⁶⁹ The accelerated depreciation used for ratemaking purposes from 1977-1983 is specified in Ex. ATC-84 through ATC-88, Sheet E (2006) (Highly Confidential) in each of the Carriers past 100 annual rate filings.⁷⁰

Carriers rely on in setting their rates stated that TSM depreciation was used to set rates)). *See also*, Ex. A/T-174 at 87-90 (Van Hoecke); Carrier witnesses Toof, Washington, Wetmore and Ganz (Tr. 867, 1542, 1666, 2040).

⁶⁷ *Trans Alaska*, 33 FERC ¶ 61, 064 at 61,139 (1985). The record reflects that the Carriers reduced their refund obligations through the accelerated depreciation. Exs. A/T-75 at 14; A/T-183.

⁶⁸ The deposition of Dr. Horst states that the TSM-6 applied back to 1969 (the first year of construction expenses attributable to TAPS. Ex. A/T-196 at 222 line 4-6.

⁶⁹ Other experts have testified in various proceedings. *See* Ex. A/T-238 (Williams) (he would expect depreciation in rates to be used for ratemaking purposes); Ex. A/T-212(Folmar) (TSM depreciation was used to set rates.)

⁷⁰ The Carriers' rate filings use the amounts of accelerated depreciation. However, ATC-84 through ATC-88, Sheet N refers to the accelerated depreciation as

101. The Carriers posit varied arguments claiming that the Stipulation and Form 6⁷¹ should be used in the Opinion 154-B presentation.⁷² It is noted that the Carriers' claim that the Stipulation remains in place as to non-settling parties is baseless. First, the terms of the TSA rendered the Stipulation invalid.⁷³ The Stipulation is inconsistent with the TSA as it uses straight-line depreciation while the TSA uses accelerated depreciation.⁷⁴ Second, Anadarko/Tesoro's statement that "there is no realistic way for the 1982 Depreciation Stipulation and the Interstate Settlement to 'remain in effect simultaneously'" since no shipper is a signatory to the TSA is also a persuasive conclusion. A/T RB at 36. The Commission has previously held that the books of the regulated entities do not control in setting rates.⁷⁵ The evidence in this case reflects that the Carriers maintain four sets of books (Tax, GAAP, FERC reporting and FERC ratemaking for TAPS). Ex. A/T-229 at E-14000186. Moreover, the reporting books record depreciation on a straight line basis and the FERC

"book" depreciation. Thus, there is a contradiction between the Carriers rate filings and the position they have taken in this proceeding.

⁷¹ The record demonstrates that the Carriers' Form 6 have not been maintained in a manner consistent with the 1982 Stipulation. Anadarko/Tesoro witness Sullivan testified on the multiple deficiencies in the quality of the data being reported to the Commission. Tr. at 5402.

⁷² Internal reports and communications of the Carriers dating to 1998 contradict the Carriers current position. See Ex. A/T192 (graphs illustrating the front-end loading of the depreciation as amounts recovered thru tariffs); Ex. A/T-186 (memorandum explaining accelerated return on capital which caused a timing difference with book accounting); Ex. A/T-188 (memorandum responding to "profit" the depreciation allowance embedded in the revenues is greater than that reflected on the financial records). Other memos confirm that the Carriers may be motivated to have the highest rate possible to decrease the combined government income (taxes and royalties). Ex. A/T-187. The Carriers front-end loading of depreciation saved the owners of TAPS approximately \$1.5 billion in windfall profits taxes. Ex. A/T-184.

⁷³ See A/T-190 at Section III-5 (p. 26) ("Any stipulation or agreement previously entered into in the TAPS proceeding by the parties to this Agreement shall continue to be, to the extent not inconsistent with the Agreement, in full force and effect between the parties to this Agreement."). Staff RB at 29.

⁷⁴ The accumulated depreciation exceeds the accumulated "booked" depreciation by approximately \$1.7 billion. Ex. ATC-266. In comments opposing the TSA, Sohio illustrated that the TSM depreciation exceeds straight line depreciation from 1978-1991. Ex. SOA-57, Attachment B.

⁷⁵ *Virginia State Corp. Comm'n v. FERC*, 468 F. 3d 845, 847 (D.C. Cir 2006); *Williston Basin*, 55 FERC at 62,008, 56 FERC at 61,370.

ratemaking books record depreciation on an accelerated basis pursuant to TSM.⁷⁶ Finally, Anadarko/Tesoro's and Staff's other arguments are similarly persuasive.⁷⁷ To apply the balances suggested by the Carriers would result in double recovery and an artificially inflated rate base by over \$481 million.⁷⁸ Ex. A/T-143 at 20, Illus. 8. Thus, it is the amount of accumulated depreciation contained in the Carriers annual rate filings that will be plugged into the Opinion 154-B methodology. Ex. A/T-144, WP2 at 5:7; Ex. A/T -146, WP2 at 4:7.

Issue III.B.2. Are the Carriers entitled to an adjustment to rate base for deferred returns, and if so, what is the appropriate amount?

102. The Carriers claim that the deferred return amount used by Anadarko/Tesoro is not appropriate because it results in a low deferred return balance. The Carriers claim that the TSM deferred return is not consistent with Opinion 154-B deferred return. First, the Carriers state that Anadarko/Tesoro use the incorrect amortization schedule. According to the Carriers, *Lakehead Pipeline Company*, 71 FERC ¶ 61,338 (1995), *reh'g denied*, 75 FERC ¶ 61,181 at 61,591 (1996) (*Lakehead*), requires the deferral to be capitalized and recovered through amortization charges (or trended) under Opinion 154-B for all years after 1983. The Carriers state that TSM uses the stipulated depreciation factors in TSA Exhibit F to amortize the deferred balance while the appropriate depreciation schedule for Opinion 154-B is set forth in the Stipulation. Second, the Carriers claim that under the TSM, both the TSM Depreciation and the recovery of TSM Deferred Return are subtracted from the rate base before applying the inflation factor thereby reducing the amount of TSM Deferred Return to be recovered in later years. In addition, the Carriers contend that the TSM carrier

⁷⁶ The accelerated depreciation was established by the TSA which provided a "small upfront refund obligation." Ex. A/T -229 at 14000185.

⁷⁷ See A/T RB at 33-42; Staff RB at 30-42. The Carriers arguments concerning the Form 73 orders also fails because as witness Sullivan confirmed, those orders only required oil pipelines to begin submitting depreciation data in magnetic tape form. A/T RB at 39; Staff RB at 32 (citing Tr. at 5569-70, 5574-75, 5578 (Sullivan)). The Form 73 orders were not about ratemaking, so as Staff again clarifies, the orders did not change or address how ratemaking is affected when actual depreciation recoveries differ from book accounting depreciation. *Id.*⁷⁷ Moreover, the Carriers' position in the case at bar is contrary to their previous position regarding revisions to Sheet 700 of FERC Form 6 reports. They asserted in the cited proceeding that the most relevant information is the TSA supporting information provided to the Commission each year in annual tariff filings. Ex. A/T-191 at 4-5.

⁷⁸ A/T RB at 36 (citing Ex. A/T-143 at 20, Illus. 8 showing that to get to the Carriers' Opinion 154-B rate base accelerated depreciation has to be added back in).

property base to which TSM deferred return is applied, excluded \$450 million excluded for settlement purposes.

103. Anadarko/Tesoro state that they will accept the deferred returns balances, and related amortization amounts contained in the Carriers' 2005 and 2006 rate filings (\$175 million for 2006).⁷⁹ Although Anadarko/Tesoro have accepted these amounts, they still believe the amounts are excessive. Staff also agrees that Anadarko/Tesoro have used the correct amounts. Staff states that the amount of deferred returns included in rate base should also reflect the amounts previously amortized on an accelerated basis and collected in the Carriers' rates from 1977 forward. Staff also contends that the balances the Carriers use in their Opinion 154-B presentation are grossly overstated. Last, Staff states that if any deferred returns are to be included in rate base, the amounts proposed by Anadarko/Tesoro are the appropriate amounts to use.

104. However, Anadarko/Tesoro assert that they do not agree with the Carriers' restatement of their deferred returns balance to more than \$1 billion in the Carriers' Opinion 154-B proxy. Anadarko/Tesoro contend that the Carriers' balance for deferred returns is inappropriate because the Carriers' witness Mr. Van Hoecke: (1) calculates deferred earnings based on a portion of the \$450 million that has already been fully recovered; (2) retroactively inflates property balances by restating the Carriers' recovery of investment from an accelerated to a straight-line basis; (3) retroactively inflates AFUDC by recalculating the Carriers' actual balances with backcasted equity-rich capital structures and through inflated and uniform equity rates of return (as high as 22%); (4) inflates deferred earnings by including deferred earnings on the unamortized balance of unauthorized starting rate base; and (5) inflates deferred earnings by amortizing the deferred earnings balance on a straight-line basis ignoring that the Carriers have already recovered deferred earnings on an accelerated basis.⁸⁰

Discussion/Findings

105. Staff correctly points out that deferred return is a ratemaking concept used in a TOC methodology in Opinion 154-B. Under TOC the inflation portion of the rate of return on equity is extracted, leaving a real rate of return. The real rate of return is

⁷⁹ Anadarko/Tesoro claim that there is evidence in the record that would support FERC's decision to eliminate the deferred return balance from the rate base. According to Anadarko/Tesoro, Exhibit A/T-261 illustrates that there was no return deferred and that the Carriers have overcollected at least \$8 billion from shippers. A/T IB at 59 n.50 (citing Tr. at 6032-6035).

⁸⁰ A/T IB at 61-62.

applied to the pipeline's equity share of rate base to determine the yearly allowed equity return in dollars. The dollars related to the inflation portion of the equity return, are "deferred" for recovery in future rates. In future rates the deferred amounts are added to rate base as an equity rate base "write-up" (the equity portion of rate base is "trended" up), and amortized as an expense like depreciation over the useful life of the pipeline.⁸¹

106. Staff's reasoning is correct and falls in line with the conclusions reached above.⁸² The Carriers' arguments concerning the differences between the TSM deferred returns and Opinion 154-B returns has no decisional impact *vis a vis* the amounts collected in the Carriers' rates over the years. *See id.* It is irrelevant that the TSM calculations of deferred returns is inconsistent with Opinion 154-B calculations and the Commission's pronouncements implementing Opinion 154-B in *Lakehead*.⁸³ Mr. Van Hoecke's (Carriers witness) approach (adding anew the deferred earnings) results in double recovery and is rejected.

107. Staff and Anadarko/Tesoro are correct that the deferred return amounts have already been collected via the TSM through the Carriers' use of a 100% equity structure⁸⁴ and APB.⁸⁵ The TSM acted much like TOC, deferring a specified amount of return dollars from early years to later years. The accelerated depreciation schedule and the plant balances are stated in the TSM formula and in the Carriers rate filings, the accelerated recovery of deferred return and the specific TSM deferred return balances and annual deferred return expenses were included in the Carriers 2005 and 2006 rate filings.⁸⁶ The Carriers have already recovered the deferred return element; however, as Staff notes, "to be true to the approach, we must take the state of the ratemaking record as we find it." *See* Staff IB at 53, A/T IB at 60.

108. The Carriers argue that *Lakehead* and other Commission pronouncements require pipelines that existed prior to Opinion 154-B to begin the calculation of

⁸¹ *Opinion 154-B*, 31 FERC, *supra*, at 61,834-35; Staff IB at 51-52.

⁸² Staff RB at 36.

⁸³ *See* A/T RB at 45.

⁸⁴ *See* Staff IB at 53; ATC-14, Sections II-6 (p. 15), II-7 (p.17), II-8 (p.18) (stating that the amounts are to be included in the TRR); Ex. A/T 3 at 39-40 (Brown); Ex. A/T-79 at 23 (Sullivan).

⁸⁵ *See* Staff IB at 53; Ex. A/T-3 at 39-41 (Brown); Ex. A/T-79 at 23 (Sullivan).

⁸⁶ ATC-84, Sheet E, line 121 at 34, 40, 46, 52; Toof, Tr. 5101-02; Grasso, Tr. 5985-86.828, 836, 839-40, 853-56; Brown, Tr. 4679-8.

deferred return with the pipelines' rate base beginning December 31, 1983.⁸⁷ Staff agrees that in *Lakehead* the Commission determined that in transitioning from a valuation to a cost-based TOC, the appropriate starting rate base under the TOC methodology is the balance as of the date Opinion 154-B became effective (December 31, 1983). Staff IB at 55. However, Staff effectively refutes the Carriers' argument that the correct deferred return balance must be calculated in accordance with the Carrier's Opinion 154-B proxy. *Id.*⁸⁸ As a matter of fact, citing SFPP⁸⁹ Staff correctly argues that the Carriers cannot backcast and recreate rates. The holding in SFPP is right on point, when setting a cost based rate for the future there is no need to allow an additional adjustment for inflation already recognized and collected in rates.⁹⁰

100. Staff states that Lakehead's rates were charged under the valuation methodology and did not include a deferred return cost component. *Id.* Additionally, Staff aptly notes that in this case, the deferred balances and annual deferred costs are known and reflected in the Carriers' TSM filings. *Id.* Staff's arguments are persuasive, and as discussed above, the appropriate amounts to use are those that reflect what the Carriers' have actually collected in rates. Those amounts are

⁸⁷ Carriers' IB at 56; *Lakehead*, 75 FERC at 61,591.

⁸⁸ Evidence in this case indicates that the Carriers have collected approximately \$6.6 billion in deferred earnings. Ex. A/T-44 & ATC-23, Sum Ln. 121, Amortization of Differed Returns, minus Ln. 7, Accumulated Amount of AFUDC; Ex. A/T-145, Stmt. E.

⁸⁹ *SFPP supra*, 117 FERC at 12-16.

⁹⁰ Anadarko/Tesoro and Staff explain that it could be concluded that there should be no allowance for deferred return from prior periods due to the TSM. Witnesses Brown and Sullivan (A/T) testified that TSM calculated deferred returns on remaining investment using 100% equity structure. This assumes incorrectly that the pipeline was constructed with only equity, overstates the deferred return, and violated the principle of Opinion 154-B that deferred returns are not allowed on debt-financed rate base. Ex. A/T-3 at 39-41. Additionally, after 1989, TSM allowed a larger nominal return known as Allowance Per Barrel (APB) adjusted for inflation yearly back to 1983. ATC-14, §II-7(b); Ex. A/T 3 at 40; Ex. A/T-79 at 23; Tr. 38 at 5924-26; Ex. A/T-180 at 13. (Horst described APB as allowing the Carriers to earn a profit as long as ANS was transported. *Id.* at 14. The APB charge was originally \$0.35 in 1989 and now is \$1.19 in 2006. In conclusion, both Staff and Anadarko and Tesoro assert that the TSM overstated deferred return and after 1989 inflation for return purposes has been more than recovered in TSM. However, since Anadarko and Tesoro accept the amounts in the Carriers' rate filings this point is made for illustrative purposes only.

contained in the Carriers' TSM filings. The Carriers' attempt to use the amount of their deferred returns reflected in Form 6 is therefore rejected. Carriers' RB at 45. The Carriers' claims that the TSM item labeled "deferred return" cannot be considered "actual return" is accordingly rejected.⁹¹

110. Thus, the appropriate adjustment and amounts for deferred returns are reflected in Anadarko/Tesoro's Opinion-154-B cost-of-service presentation. The amount of deferred return in 2005 is \$198.31 (in millions). Ex. A/T-144, WP2 at 5:18 (Col. "2004"). The amount for 2006 is \$175.283 (in millions) A/T 146, WP2 at 4:18 (Col. "2005").

Issue III.B.3. What is the appropriate amount of AFUDC?

111. The Carriers contend that Mr. Van Hoecke's Allowance for Funds Used During Construction (AFUDC) balances must be used for Opinion 154-B. According to the Carriers, Mr. Van Hoecke calculated the AFUDC in accordance with the Commission's oil pipeline cost of service regulations set forth in 18 C.F.R. § 346.2(c)(6) (2006). The Carriers state that Anadarko/Tesoro have incorrectly extracted the amounts in the Carriers TSM submissions and, in addition, did not follow the Commission's regulations. However, the Carriers do not recognize that this issue is purely derivative of other issues.⁹²

112. Anadarko/Tesoro and Staff state that the appropriate balance for AFUDC to be included in rate base is the amount reported in the Carriers' annual rate filings. Anadarko/Tesoro state that the AFUDC amounts included in the Carriers' rate base for the period 1977 through 1983 are shown in TSM-6. All subsequent years are shown in the Carriers' annual rate filings, Anadarko/Tesoro contend.⁹³ Anadarko/Tesoro and Staff also state that these balances reflect the amounts that have

⁹¹ The Carriers state that contention is based on the same arguments in Section III.A. which basically claims that third parties cannot rely on TSM elements which are an inseparable settlement package. In addition, the Carriers' arguments concerning Staff's and Anadarko/Tesoro's statements that the Carriers' over collected deferred return and this component could be eliminated from the Opinion 154-B calculation is not addressed (along with the Carriers' retroactive ratemaking arguments) since Anadarko/Tesoro and Staff have agreed to accept the Carriers' balances which includes deferred return.

⁹² Carriers RB at 47.

⁹³ Anadarko/Tesoro state that the AFUDC balances are calculated consistently with the principles in Opinion 154-B, but are for a different period because they pre-date Opinion 154-B. A/T IB at 63.

already been collected by the Carriers. In addition, Anadarko/Tesoro state that the deferred balance has been amortized from 1977 through 2005.

113. Staff states that AFUDC is also included in rate base and recovered in basically the same manner as the property balances discussed in Issue III.B.1. Staff IB at 56. Thus, Staff asserts, the amount used for AFUDC must be consistent with the property balance issue. Staff also claims that AFUDC was one of the rate elements whose recovery was accelerated under the TSA in order to allow the Carriers to avoid making any refunds for the 1977 through 1981 period and limited refunds for the 1982 through 1985 period. The Carriers' balances for AFUDC are inappropriate, Anadarko/Tesoro and Staff assert, because the Carriers ignore the AFUDC that has been included in the Carriers' rates and instead, recalculate it. Thus, using the Carriers' amounts would result in double recovery, Anadarko/Tesoro and Staff contend.

Discussion/Findings

114. As Staff explains, AFUDC "is a method of deferring, in a capital account, costs associated with plants under construction for inclusion in a utility's rate base once the plant is put into service." Staff IB at 56 (citing *Kentucky Utilities Co. v. FERC*, 760 F.2d 1321, 1323 (D.C. Cir. 1985)). The amounts used by Anadarko/Tesoro reflect the amount of AFUDC actually collected by the Carriers. A/T-3 at 31 (Brown); Tr. 5930,5954-55, 5983 (Grasso); Tr. 5824-25 (Grasso). Thus, the appropriate amounts of AFUDC to include in rate base are listed in Exhibits A/T -144 Stmt. F (2005), A/T-146, Stmt F (2006).

Issue III.B.4. What is the appropriate amount of ADIT?

115. The Carriers state that the only issue with regard to Accumulated Deferred Income Tax (ADIT) is the appropriate input for past depreciation expense. The Carriers claim that Mr. Van Hoecke has correctly used the depreciation expense balances recorded in the Form 6 annual reports pursuant to the Stipulation. TSM derived depreciation should not be used, the Carriers assert.

115. Anadarko/Tesoro contend that the appropriate balance for ADIT is reflected in the Carriers' annual rate filings. The Carriers' Opinion 154-B presentation, Anadarko/Tesoro assert, ignores the ADIT that has been included in the rate filings, and instead, recalculates the amount. Anadarko/Tesoro claim that the Carriers have added \$183.11 million to their Opinion 154-B rate base in 2006 for items including ADIT. A/T IB at 65 (citing Ex. A/T-78 at 55; Ex. A/T-143 at 20 Illus. 8). According to Anadarko/Tesoro, this additional amount is the derivative result of the impact on ADIT, AFUDC, and working capital when the Carriers' Opinion 154-B recalculates and adds deferred earnings, a starting rate base adjustment, and then ignores the

accelerated portion of the depreciation to the Carriers' filed rate base. Staff states that ADIT is a mechanically calculated number that partially derives from the deferred earnings, depreciation, and other rate base assumptions used to calculate the rates. Staff IB at 57 (citing A/T-78 at 55). Thus, Staff asserts, once these issues are resolved ADIT can be determined.

Discussion/Findings

117. The parties seem to agree that the resolution of the issue concerning the appropriate depreciation expense will determine the outcome of this issue. ADIT arises because "certain deductions from income are recognized by the IRS for tax purposes before they are recognized for book or rate purposes. The effect of the earlier recognition of deductions for tax purposes is that ratepayers will provide the pipeline with revenues to cover taxes which will not actually be paid until some time in the future." Staff IB at 57. In addition, Staff states that "ADIT is the cumulative amount of such revenues which have been supplied by ratepayers but not yet paid out in taxes by the pipeline, and Commission practice requires this prepaid expense to be deducted from rate base." Staff IB (citing *Trans Alaska Pipeline Sys.*, 10 FERC ¶ 63,026 at 65,218 (1980); Opinion 154-B, 31 FERC at 61,837 n.55).

118. Based on the determinations in this decision it is found that the appropriate amounts of ADIT are reflected in the Carriers annual rate filings as stated by Anadarko/Tesoro and Staff. Thus, the amount of ADIT for 2005 is \$46.20 (in millions). A/T IB at 64; Ex. A/T-144, Stmt. E, ln. 11. The amount for 2006 is \$43.00 (in millions). A/T IB at 64; A/T-146, Stmt. E, ln. 11.

Issue III.B.5. Are the Carriers entitled to a starting rate base write-up, and if so what is the appropriate amount?

119. The Carriers claim that Opinion 154-B presumed that all oil pipelines in existence as of the date of the opinion (June 28, 1985) would be allowed the starting rate base (SRB) write-up. Thus, the Carriers contend, the burden is on the challenging party to show why the SRB write-up should not be permitted in a particular case. Carriers' IB at 61 (citing *Lakehead*, 71 FERC at 62,311). The Carriers state that the portion of the SRB that exceeds the Carriers' depreciated original cost rate is referred to as the SRB write-up. Mr. Van Hoecke, the Carriers assert, correctly calculated the SRB using the Cost of Reproduction New (CRN) calculated by Mr. Ganz.

120. Flint Hills claims that a total of \$322.52 million or \$.99 per barrel needs to be added to the SRB. This consists of two components which Flint Hills claims are an inclusion of an SRB amount and a corresponding deferred return back to 1983. Flint Hills also contends that Anadarko/Tesoro's rejection of a SRB write up is meritless.

Flint Hills posits arguments similar to the Carriers' which, for the most part, state that without the TSA, the TAPS rate base would have been calculated using valuation and that prior to the TSM the TAPS rates were filed under the ICC valuation methodology. Alternatively, Flint Hills suggests a transition cost adjustment for the remaining APB as compensation for the loss of the APB if the TSA does not run its course.

121. The Carriers state that Anadarko/Tesoro's arguments that the Carriers are not entitled to a SRB write-up are incorrect. First, the Carriers assert that contrary to Anadarko/Tesoro's assertions, the Carriers relied on the ICC valuation methodology for the entire period from start-up through approval of the TSA. Second, the Carriers claim that they relied on the valuation methodology long after the initial rates were filed. The Carriers claim that they worked with the Commission's Valuation Branch to finalize the valuation reports on TAPS and that they continued to be subject to the Commission's valuation regulations even in late 1984. The Carriers claim that it was not until seven years after the initial TAPS rates were set that it can be fairly said that an oil pipeline should no longer rely on valuation. Third, the Carriers assert that Anadarko/Tesoro's contentions that final TAPS rates were not set under valuation and that a final valuation report was not issued do not rebut the presumption of their entitlement to an SRB write-up. Last, the Carriers claim that inclusion of the SRB write-up does not inflate their Opinion 154-B rate base since, as Mr. Van Hoecke has shown, including the SRB write-up results in a lower rate base figure as of December 31, 1983.

122. Anadarko/Tesoro and Staff argue that the Carriers are not entitled to a SRB write-up because the Carriers are not transitioning from regulation under the valuation methodology. According to Anadarko/Tesoro and Staff, the Commission only intended the SRB to be a transitional rate base for existing pipelines that had assets that were valued under the valuation formula. In fact, they state that Opinion 154-B only allowed a SRB adjustment for assets that were transitioning from valuation to TOC. No valuation order was ever issued for TAPS by the ICC or FERC, Anadarko/Tesoro and Staff claim. Anadarko/Tesoro also assert that every final rate on TAPS for the past 30 years has been based on the TSM and not the valuation methodology. Thus, Anadarko/Tesoro state, they did not include a SRB adjustment in their Opinion 154-B presentation. The Carriers inflate their Opinion 154-B proxy with a SRB adjustment of \$421.10 million calculated (backcasted) for 2006, Anadarko/Tesoro and Staff contend. Staff further asserts that neither the TSA nor the TSM mention the valuation methodology. This is relevant Staff states, since from the commencement of TAPS operations to date, the TSA has established the revenue requirements on TAPS.

Discussion/Findings

123. The Carriers are not entitled to a SRB write-up because the Carriers' assets were never valued under the valuation methodology. The Carriers and Staff aptly note that with respect to the SRB write-up, Opinion 154-B left the door open for "a participant in a rate case [to] raise this issue and attempt to prove that a particular company is not entitled to the instant starting rate base."⁹⁴ Staff and Anadarko/Tesoro have shown that the Carriers are not entitled to a SRB write-up and, accordingly the Carriers' and Flint Hills' arguments are rejected. Accordingly, it is found that Anadarko and Tesoro have rebutted the Carriers' alleged presumption and thus, the Carriers are not entitled to an SRB write-up.

124. First, the Carriers never relied on valuation. The Commission's language in Opinion 154-B is clear. The SRB write-up was only intended for "existing assets that are currently valued under the valuation formula...." Opinion 154-B, 31 FERC at 61,833. Importantly, the TAPS rates were never calculated under the valuation formula. The Carriers claim that their interim rates were based on valuation. Carriers' IB at 62-64. However, Staff and Anadarko/Tesoro have shown that this argument fails for several reasons. The Carriers' interim rates were not final and subject to refund and when the final rates were set on TAPS, those rates were based on the TSM and not valuation.⁹⁵ The Carriers simply never had an approved rate on TAPS under the valuation method. *Id.*; Staff RB at 39. It is also telling that the Commission never issued the Carriers a valuation report.⁹⁶ In addition, the Carriers' initial filings were based on different methods.⁹⁷

⁹⁴ Opinion 154-B, 31 FERC at 61,836 (citation omitted); The Carriers argue that *Lakehead Pipe Line Co., L.P.*, stands for the proposition that all oil pipelines are presumptively entitled to a SRB write-up. 71 FERC ¶ 61,338. The Commission noted that Lakehead had used the valuation method "long-term" and this is why the Commission stated that Lakehead was presumptively entitled to a SRB. *Id.* at 62,309. The record here, as discussed below, indicates that the Carriers never used valuation.

⁹⁵ A/T IB at 68; RB at 47-48; Staff RB at 39; IB at 59-60; Ex. A/T-79 at 19-20 (Sullivan stated that the Carriers were never regulated under the valuation rate method); Ex. A/T-3 at 35 (Brown stated that "[t]he Carriers' rates from 1977 to date have been calculated under the TSM and accepted under the terms of the Interstate Settlement... the Carriers have never had their rates approved or set by the ICC or by the Commission under the ICC valuation methodology.").

⁹⁶ A/T RB at 47; IB at 65; Staff IB at 60; RB at 41; Ex. A/T-79 at 20 (Sullivan); Tr. 2074 (Ganz).

⁹⁷ A/T RB at 51; IB at 67 n.55; Tr. 5800-01 (Grasso) (The eight Carriers filed their initial rate filings at the ICC using different rate theories: some were original

125. The Carriers' arguments concerning *Lakehead Pipe Line Co., L.P.*, 75 FERC at 61,591 are flawed. Contrary to the Carriers' assertions, in Opinion 154-B, the Commission specifically stated that it does make a difference which methodology the pipelines' rates were based on. Carriers RB at 47-48. The Commission stated that the SRB adjustment was intended for "existing assets that are *currently valued under the valuation formula...*" Opinion 154-B, 31 FERC at 61,836 (emphasis added). This language precludes pipelines that were not using the valuation method at the time Opinion 154-B was issued from entitlement to a SRB write-up. *See id.*

Issue III.B.6. What is the appropriate amount of other rate base items?

126. The Carriers state that for the reasons listed in section III.B.1 the other rate base items which include land, working capital, and miscellaneous plant adjustments must be based on the Carriers' Form 6 balances. Anadarko/Tesco claim that there should be no other material rate base items except for the credit to rate base for DR&R collections. Staff states that other rate base items such as land and working capital are derivative of other issues and will follow from rulings on those other issues.

Discussion/Findings

127. The parties recognize that the resolution of this issue is tied to the findings concerning Issue III.B.1. In that section, it was found that the correct inputs are found in the Carriers' annual rate filings. Staff discusses the \$450 million exclusion from rate base in this section. It has already been found that the \$450 will be excluded from rate base as discussed above. Thus, there are no other material rate base items at issue with the exception of the DR&R rate base credit issue discussed below.

Issue III.B.7. Should asserted DR&R collections and earnings be credited against rate base, and if so, what is the appropriate amount?

128. This issue is discussed in section III.D.

cost: and some were "original cost filings guised as valuation." Tr. at 5800-5801. The common theme being to file "the highest possible tariff... in order to minimize government income [taxes and royalties] from the field and the pipeline." Ex. A/T-187 at 1. The ICC interim rates were not intended to have permanent effect and were not "prescribed" rates. Ex. A/T-157 at 1, 4, 7. Therefore, it is found that the Carriers interim rates do not support their claims. Consequently, the Carriers SRB calculations are not given any weight.

Issue III.C. What is the appropriate level of operating expenses excluding depreciation and DR&R?

129. Anadarko/Tesoro and Staff state that they accept the Carriers' operating expenses, exclusive of depreciation for 2005 and 2006. Ex. A/T-143 at 5-6, and Illus. 6; Ex. ATC 37-41, Stmt. B (2005); Ex. ATC-90-94, Stmt. B (2006); Carriers IB at 70 n.63. As a result, there is no issue to resolve.

Issue III.D. What is the appropriate depreciation expense?

130. The Carriers argue that the Stipulation is still in effect, and accordingly, the proper amount of depreciation expense is reflected in Form 6. Moreover, the Carriers assert, since they have not proposed to change the approved depreciable life of 2011, that end-life remains in effect. The Carriers contend that if the Commission opts to revise the depreciable life, the Carriers have also produced a depreciation study using an end-life of 2034. These recalculated amounts, the Carriers assert, were plugged into the Opinion 154-B model and also prove that the Carriers' rates are just and reasonable using the 2034 depreciable life. The Carriers claim that Anadarko/Tesoro's depreciation study, done by Mr. Sullivan, is flawed. According to the Carriers, Mr. Sullivan's study is flawed because: (1) the property and accumulated depreciation balances are derived from the TSM and (2) because TSM-derived balances are not broken out by property account, Mr. Sullivan had to allocate TSM amounts arbitrarily based on Form 6.

131. Anadarko/Tesoro state that they have calculated the correct depreciation expense using the Carriers' annual rate filings that reflect the Carriers' previous recovery of investment and a remaining life of 2034. Anadarko/Tesoro claim that all the parties agree that the useful life of TAPS will extend through at least 2034. According to Anadarko/Tesoro, the Carriers' rate position is inconsistent because their Opinion 154-B presentation uses a useful life ending in 2034 while their filed rates use an ending date of 2011. Anadarko/Tesoro contend that the Carriers' depreciation study is flawed because it relies on incorrect plant balances from Form 6 that do not reflect their previous investment and Mr. Spanos failed to adjust for an overaccrual.

132. Anadarko/Tesoro state that contrary to the Carriers arguments, Mr. Sullivan only had to allocate the property balances to individual accounts because the Carriers failed to properly update their depreciation study. The Carriers TSM filings did not break out the overall property balances by account, Anadarko/Tesoro claim, and consequently, the lack of accurate account-by-account balances was caused by the Carriers. Staff states that the appropriate property balances are found in the Carriers'

rate filings. In addition, Staff contends that the Carriers' 2034 depreciation study conducted by Mr. Spanos, should also be used.

Discussion/Findings

133. The parties agree that depreciation expense is calculated using the appropriate net property balance and a reasonable estimate of the remaining useful life of TAPS. Carriers RB at 55; A/T IB at 73; Staff IB at 66; RB at 46. First, the correct plant balances are those proposed by Anadarko/Tesoro as discussed in section III.B.1. The Carriers' depreciation study based on an end-life of 2034 used the Form 6 balances which do not reflect previously recovered amounts.⁹⁸ The Carriers take issue with Anadarko/Tesoro's property allocation. Mr. Sullivan properly allocated the correct property balances to individual accounts using the proportions employed by Mr. Spanos. Tr. 5468-71 (Sullivan). Anadarko/Tesoro's study used the balances from the Carriers' TSM filings and the survivor curves used by Mr. Spanos.⁹⁹ In addition, Mr. Sullivan corrected for an overaccrual of \$147 million which Mr. Spanos admittedly had not done in his own study. Tr. 1741-44 (Spanos); Tr. 5470-71 (Sullivan). Again, Mr. Sullivan's testimony is credible and is accorded substantial weight. Thus, Anadarko/Tesoro's depreciation study will be used since it is based on correct and more reliable data. Second, the correct end-life of TAPS is 2034 as corroborated by several witnesses.¹⁰⁰ Accordingly, it is found that the correct depreciation expense balances are those proposed by Anadarko/Tesoro.¹⁰¹

⁹⁸ Tr. 1707, Ex. A/T-141 at 7. The Stipulation is no longer in effect, therefore the Form 6 balances should not be used. See Section II.B.1, *supra*.

⁹⁹ Staff and the Carriers advocate the use of Spanos's study which includes his survivor curves, as long as it applies the correct property balances. Staff IB at 66; Carriers IB at 70-71; Tr. 5471 (Sullivan).

¹⁰⁰ Ex. A/T-141 at 4 (Sullivan); A/T-79 at 18-19 (Sullivan); ATC-4 at 46 (Kalt); ATC-154 at 4 (Spanos); A/T-32 at 4 (TAPS right-of-way-extended to 2034); Carriers' RB at 56.

¹⁰¹ The depreciation expense for 2005 is \$14.06 (in millions). Ex. A/T-144, Stmt B4, ln. 6. The depreciation factor for 2005 is 3.8095. A/T-142; Tr. at 5745-46 (Grasso describes the calculation of the depreciation factor). The depreciation expense for 2006 is \$13.48 (in millions). Ex. A/T-146 Stmt. B4, ln. 6; Ex. A/T-142. Anadarko/Tesoro note that Mr. Grasso agreed that for 2006 it would be appropriate to modify the depreciation factor to reflect one year less of remaining life (from 3.8% to 3.9%). Mr. Grasso verified that the change would increase depreciation expense slightly, but would not impact the overall TAPS rate. A/T IB at 75; Tr. 5988-89.

Issue III.E. What is the appropriate DR&R expense?¹⁰²

134. The Carriers state that the TSA included a negotiated DR&R allowance in the TSM ceiling rates (\$2.2 million for 2005 and \$2.1 million for 2006). Mr. Van Hoecke did not include any amounts for DR&R when calculating the Opinion 154-B rates, the Carriers assert. However, the Carriers note that in deciding to exclude these amounts, Mr. Van Hoecke did not make a determination as to whether DR&R expenses were necessary or appropriate. The Carriers contend that their filed rates are just and reasonable whether or not they include any amounts for DR&R and, accordingly, they should be able to recover the full amount of their filed rates for 2005 and 2006.

135. Anadarko/Tesoro and Staff argue that there should be no expense allowed for DR&R. The Carriers have failed to support the allowance for DR&R included in their filed rates, Anadarko/Tesoro contend. In addition, Anadarko/Tesoro and Staff assert that the Carriers' Opinion 154-B proxy did not include any DR&R allowance and the Carriers did not provide any evidence related to this issue. Thus, Anadarko/Tesoro and Staff conclude, the Carriers' DR&R allowance should be rejected. Anadarko/Tesoro and Staff contend that the Carriers fail to account for the amounts of DR&R they have already recovered and associated earnings. The Carriers' massive front-loaded recovery of DR&R is well documented in the record, Anadarko/Tesoro claim. Anadarko/Tesoro and Staff also argue that the Carriers' parents used the funds as unrestricted capital and should be required to account for such earnings. Finally, Anadarko/Tesoro claim that the Carriers now have approximately \$15 billion more in DR&R funds than they would need to conduct DR&R activities.

136. Anadarko/Tesoro and Staff assert that several key assumptions underlying the DR&R collection schedule have changed and will cause the Carriers collections to grow faster than originally anticipated when the schedule was established. They state that the assumptions changed as follows: (1) the life of TAPS was extended from 2011 to at least 2034; (2) the federal corporate income tax rate changed from 46% to the current 35%; and (3) the IRS allowed the Carriers to deduct an unanticipated \$900 million. The Carriers do not dispute these changes, Anadarko/Tesoro and Staff contend. Anadarko/Tesoro and Staff claim that based on applying an average earnings rate (attributable to the parents) the total for DR&R collections and earnings is more than \$17.2 billion. When compared to the undisputed DR&R obligation

¹⁰² This section discusses all DR&R related issues including those addressed in Issue III.B.7 (Should asserted DR&R collections and earnings be credited against rate base, and if so, what is the appropriate amount?) and Issue III.M (Are any other remedies related to DR&R appropriate in this proceeding?).

amount of \$2.63 billion proffered by the Carriers, Anadarko/Tesoro and Staff assert, there is clearly no need for further DR&R collections.

137. Staff states that the question here is what earnings assumption accurately reflects the time value of the accelerated collection of the DR&R funds and the unrestricted use of these funds by parents. Anadarko/Tesoro advocate, and Staff endorses, the use of the actual, historic, after-tax earnings rates of the parents. Staff RB at 49; A/T IB at 109. The Carriers claim that the risk-free rate is the proper rate and the rates requested by Anadarko/Tesoro and Staff are unjustified. Carriers' IB at 124.

*DR&R Rate Base Credit*¹⁰³

138. The Carriers argue that DR&R collections and earnings should not be credited against rate base. Anadarko/Tesoro's and Staff's reliance on *Kuparuk Transportation Co.*, 55 FERC ¶ 61,122 at 61,382-83 (1991) (*Kuparuk*), is misplaced, the Carriers contend. According to the Carriers, this is because in *Kuparuk* the Commission adopted an accrual methodology for DR&R and, in contrast, an annuity methodology is used for TAPS. The difference, the Carriers contend, is that the DR&R amounts in this case were computed on an annuity basis and the earnings on the collections are assumed to be necessary to fund the ultimate DR&R obligation. Thus, the Carriers assert, the funds will not be sufficient to cover the obligation if the Carriers do not retain the amounts collected. Allowing a rate base credit would amount to crediting the shippers with presumed earnings twice – once in the annuity formula and again through the rate base deduction, the Carriers contend. Finally, the Carriers claim that their DR&R collections and earnings are insufficient to fund the Carriers' ultimate DR&R obligation and crediting the rate base for these amounts would only further complicate the problem.

139. According to Flint Hills, the principle of intergenerational equity attempts to treat shippers equally over a period of time by ensuring that shippers during one period do not pay disproportionately higher costs than later shippers. Virtually all of the DR&R funds were collected during the first half of the TAPS life, so no funds need to be collected going forward, Flint Hills asserts. Flint Hills argues that intergenerational equity is a requirement for rates to be just and reasonable and must be applied to part of the DR&R funds. Flint Hills claims that intergenerational equity should prevent the use of DR&R funds to reduce the rate base and future shipper's rates. Therefore, Flint Hills asserts, Anadarko/Tesoro's request to credit the rate base should be rejected. In addition, Flint Hills argues that the solution is for DR&R funds to be collected from future shippers and paid to past shippers that paid the majority of

¹⁰³ This is issue III.7.

the DR&R expense such as Williams. Since 2006 is approximately the midpoint in the life of TAPS, Flint Hills states that half of the funds can be refunded to shippers who paid the DR&R funds from 1978-2006, without interest, and those funds can then be collected from shippers from 2005 forward. Finally, Flint Hills claims this solution would also avoid the controversy as to which rate of return should apply to the earnings on these funds.

140. Anadarko/Tesoro and Staff state that DR&R should be credited to rate base. The Carriers' understate the DR&R balance and do not reflect the use of funds as unrestricted capital, they claim. Moreover, Staff states that the prepayments represent interest free loans from ratepayers, that if not properly recognized, would allow a pipeline to benefit from the time value of the funds without compensating the ratepayers. According to Anadarko/Tesoro and Staff, *Kuparuk* requires pipelines to credit rate base with DR&R collections. 55 FERC ¶ 61,382-83. Anadarko/Tesoro state that this is to: (1) compensate ratepayers for advancing those funds before they are needed for DR&R activities and (2) eliminate the issue of the interest rate at which DR&R funds will grow in the future.

141. Anadarko/Tesoro state that the Carriers' witness, Mr. Van Hoecke, has recognized that in a similar situation, pre-collected funds for future expenses should be deducted from rate base. The amount of the rate base credit in this case, Anadarko/Tesoro assert, will be limited to the amount of the Carriers' current rate base because the amount of DR&R collections and earnings exceed the rate base of \$576.86 million. Anadarko/Tesoro state that the amount of collections and earnings through 2005 totals \$17.265 billion. Staff asserts that the amount through 2004 is more than \$1.5 billion. Anadarko/Tesoro and Staff state that they are not proposing a negative rate base or automatic zeroing out of future Carrier investment. Anadarko/Tesoro claim that even with such a rate base credit, the Carriers would still recover all their operating expenses, a depreciation allowance, an amortization of deferred return from prior periods, and a tax allowance on those deferred returns.

142. Staff states that the problem in this case is that the Carriers began collecting DR&R early and in huge front-loaded amounts and, as a result, the actual collections plus the associated earnings have produced an enormous DR&R fund. The total amount, Staff contends, is both greater than the Carriers' rate base and the amount that will eventually be required to complete the DR&R task. The Commission, Staff states has allowed pipelines with a zero rate base a management fee if needed as an incentive to continue operating the line.

Other DR&R Remedies

143. The Carriers argue that the remedies requested by Anadarko/Tesoro are not necessary or appropriate. The Carriers claim that there has been no overcollection of

DR&R funds. First, the Carriers assert that this is because their liability for DR&R is unlimited and the ultimate scope and costs of DR&R is uncertain. Thus, the Carriers conclude, the relief sought is speculative and premature. Second, the Carriers argue that Anadarko/Tesoro's assumption that specific DR&R collection amounts are identifiable is inconsistent with the TSA. The Carriers were not required to account separately for such amounts and neither the TSA or the Commission's orders accepting it suggested that the amounts collected in rates were traceable to the amounts in the DR&R allowance exhibit. The Carriers assert that the overcollection analysis presented by Anadarko/Tesoro was flawed and when corrected, showed that the 2005 earnings and collections of DR&R would be \$2.365 (invested at the Moody's Double A bond rate) or \$2.06 billion (invested at the risk-free earnings rate). Use of the Carriers' parents' rate of return on the book value of equity to determine DR&R earnings is contrary to *Kuparuk* that allowed an earnings rate base on the pipeline's weighted average after-tax cost of capital. *Kuparuk*, 55 FERC at 61,382. Next, the Carriers argue that the risk-free rate is the proper rate because that is the only prudent investment strategy. The Carriers also assert that this is the proper rate because they bear the risk with regard to such investments.

144. Third, the Carriers claim that granting a refund, rate base credit or requiring a separate DR&R fund as proposed by Anadarko/Tesoro would violate the rule against retroactive ratemaking and constitute an unlawful taking. The Carriers also argue that the rule against retroactive ratemaking bars the requirement of an accounting, and in addition, argue that it is not required by the TSA. The Carriers state that any revenues that the TAPS Carriers collected for DR&R prior to 2005 have become final, are no longer subject to refund, and were collected without any restrictions or conditions. The Carriers argue that Flint Hills' proposed relief should also be rejected because Flint Hills' proposed reallocation also violates the filed rate doctrine and is not supported by precedent.

145. Anadarko/Tesoro request three additional remedies related to DR&R. First, Anadarko/Tesoro request a full accounting for all DR&R collections and earnings to date. According to Anadarko/Tesoro, the Carriers have never accounted for their DR&R collections and earnings. Anadarko/Tesoro argue that their DR&R calculations, which use the actual, historic, after-tax earnings rates of the Carriers' parents, should be accepted. The Carriers' admittedly did not invest the DR&R funds in treasuries, but instead used the amounts as unrestricted funds, and for that reason the Carriers' proposal to use the "risk free" rate should be rejected. Staff states that this request is reasonable and necessary before the Commission can consider what to do with the fund. The Commission has required an accounting for these types of funds previously and should do so here, Staff contends. Staff states that the accounting must allow the Carriers' to maintain an adequate reserve to meet the estimated costs of DR&R plus inflation for another 25 years until work is completed. Staff states that in addition to the \$576 million that the Carriers may retain, the

Carriers should also be allowed to retain the remaining obligation of \$2.054 billion. This remaining balance may still be commingled with the parents' general corporate funds, but should also be presumed to continue to earn a return at the parents' book equity rate. Staff also states that if the earnings on the \$2.054 billion does not keep up with the cost of inflation, or other changes in the cost of DR&R then the Carriers should be allowed to come to the Commission to request an adjustment to their rates. Staff RB at 78-79.

146. Second, Anadarko/Tesoro and Staff request that the amount of the overcollection be refunded to the ratepayers. Staff and Anadarko/State that the amount of funds collected far exceeds the final cost of DR&R and that amount will only grow for another 25 years. The Carriers should not be allowed to reap a windfall on the excess DR&R collections and Commission precedent does not allow pipelines a return on expense, Anadarko/Tesoro and Staff claim.

147. Third, Anadarko/Tesoro and Staff request that the Carriers be required to account for the collections and earnings and report such amounts to the Commission annually. Anadarko/Tesoro also request the establishment of either a segregated fund if an accounting is not required. In *Kuparuk*, Anadarko/Tesoro claim, the Commission declined to establish a segregated DR&R fund, on the condition that the pipeline establish internal accounting for DR&R. Anadarko/Tesoro assert that the Carriers' claim that DR&R recovery has no meaning outside the TSM is meritless. Anadarko/Tesoro claim that the remedies they are proposing will put the Carriers' DR&R recoveries and projected expenses in sync and ensure that DR&R revenues retained by the Carriers are accounted for in accordance with FERC guidelines.

148. Finally, Anadarko/Tesoro and Staff state that contrary to the Carriers' assertion, implementing a rate base credit on a prospective basis, terminating DR&R collections in the current rates which are subject to refund do not constitute retroactive ratemaking or an unlawful taking. Staff states that the uncertainty of the final cost of DR&R is not a reason for the Commission to abdicate its responsibility to monitor the amount of DR&R collected, recognize and account for the earnings the Carriers (or their parents) have made, to periodically adjust the size of the fund, and insure that in the end, the Carriers will have enough to perform the DR&R without retaining excess amounts. In addition, Staff states that DR&R costs by their nature are unlimited and unknown. However, Staff argues, this is why regulated utilities periodically adjust their rates to keep them in line with the most current cost estimate.

Discussion/Findings

149. Anadarko/Tesoro and Staff are requesting several remedies in this proceeding related to DR&R: (1) a credit to rate base (discussed by the parties in section III.B.7); (2) termination of further DR&R collections in rates (discussed by the parties in

section III.E); (3) a full accounting of DR&R collections and earnings to date; (4) refunds to ratepayers of DR&R over-collections to date; and (5) establishment of either a segregated fund or specific accounting procedures for the DR&R amounts the Carriers are permitted to retain.

DR&R expense

150. The Carriers arguments concerning specific elements of the TSA not being applicable to non-signatories was rejected above. The TSA states: "The DR&R Allowance to be included in the Total Revenue Requirement for each year to provide for the eventual dismantlement, removal and restoration of TAPS is given in Exhibit E. Ex. T/A 33 at 14 §II-4.¹⁰⁴ Exhibit E actually sets forth the DR&R allowance starting from 1984-2011. *Id.* at E1. Therefore, it is clear that the TSA included the recovery of DR&R. It is further found that the TSA DR&R amounts were collected in rates.¹⁰⁵ As Staff correctly points out, the amount collected can be pulled from the TSM. Ex. A/T-33 Lx. E; A/T-44 at 15-20. Addition of "Actual DR&R Collections" from Ex.149 totals over \$1.5 billion. So the issue remaining is what earnings these funds have accrued and what the ultimate dismantlement costs will be at the end of the useful life of the pipeline.¹⁰⁶ Until that determination is made, there can be no asserted overcollection as claimed by Anadarko/Tesoro and Staff. The parties have presented various studies and estimates of what they believe the amount of collections and earnings total to date.

151. The evidence in the record supports Anadarko/Tesoro's and Staff's contention that the assumptions underlying the DR&R payment calculations changed over time which potentially caused the Carriers to earn more interest on the collected amounts than originally anticipated. Ex. A/T-140 at 92-93. As pointed out by Mr. Brown, who provided credible testimony on this issue, these changes result in a larger amount of after tax DR&R earnings than originally anticipated when the DR&R collection schedule was established. *Id.* For instance, the useful life of TAPS is now longer

¹⁰⁴ Ex. ATC-14 at 14 (§II-4), ATC-14 at 54 (Ex. E).

¹⁰⁵ Ex. A/T-140 at 17; Ex. A/T-75 at 38-41; Ex. A/T-3 at 51; A/T-33 at Sec. II-4, Ex. E; A/T-35 at 33-34; Ex. A/T-44 at 20 ln. 117 ("DR&R Allowance"); *Trans. Alaska Pipeline Sys.*, 33 FERC at 61,139 (the Commission stated that the DR&R was based on an accelerated schedule and therefore, the expense is front-end loaded).

¹⁰⁶ Ex. ATC-157 at 11 (Browning stated since TAPS is expected to operate through 2034, "it is practically impossible to estimate, today what the ultimate costs of DR&R will be."). Browning estimated actual cost of performing DR&R at \$2.63 billion (in 2005 dollars). However, he also asserts that it could require an additional \$2.44 billion presuming removal of the entire pipeline. Exs. ATC-115 at 31, 53; ATC-157 at 3-4, 8-10.

than originally anticipated. The record evidence in this case establishes the useful life needs to be corrected to 2034. Federal corporate tax rates declined from 46% to 35%; the Carriers reached an agreement with the IRS which allowed a \$900 million tax deduction for DR&R. Ex. A/T-3 at 77, A/T-78 at 57; A/T-140 at 92-93. The record in this case also shows that the Carriers had unrestricted use of the DR&R collections. Exs. A/T-160 at 42-43; Tr. 6529-31; 6505-06 (Hanley); Tr. 5513 (Sullivan); Tr. 6040-41 (Grasso); Tr. 4030-31 (Olson).

152. While Anadarko/Tesoro's and the Carriers' yearly DR&R allowance amounts are mostly similar (with the exceptions noted below), *see* Ex. A/T-30; Ex. ATC-130, it is the earnings rate that is causing the large disparity in the parties' calculations. Anadarko/Tesoro and Staff argue that the Carriers' earnings on DR&R should account for the fact that the funds were used as unrestricted capital by the Carriers' corporate parents. A/T IB at 76; Staff IB at 68. These parties and Staff propose the use of the actual historic earnings rate of the Carriers' parents (after-tax composite returns on equity) which is as high as 28.29 percent and 27.98 percent. *See* A/T-149 at 1; A/T-143 at 46. Anadarko/Tesoro witnesses Brown and Grasso claim that the DR&R collections growing at the parents' actual historic rates will equal \$17.265 billion through 2005. Ex. AT-140 at 99-100; Ex. A/T-149.¹⁰⁷ The Carriers claim this study is riddled with errors and have offered their own "corrected" calculations which state that the DR&R collections and earnings total for 2005 would be \$2.364. Carriers IB at 119; Ex. ATC-115 at 40-43.

153. The Carriers' flatly reject the use of their parents' rate of return on equity as being too high and, similarly, that is the finding here. As the Carriers' point out, this earning rate assumes that that Carriers are engaging in risky investments. ATC-113 at 42; Carriers' IB at 124. It is not surprising that using this extraordinarily high rate results in a DR&R calculation of over \$17 billion. *See* Carriers' IB at 121; A/T IB at 77; Carriers' IB at 121. Neither Mr. Brown nor Mr. Hanley (who calculated the return on equity for the parents from 1977-2005) knew of any precedent that supports the use of the parent's return on equity. Tr. 6667, 4989; Staff IB at 68. In addition, Anadarko/Tesoro and Staff fail to cite any precedent for such a rate of return. Thus, Anadarko/Tesoro's proposed earnings rate is rejected and, accordingly, Anadarko/Tesoro's DR&R calculation using the Carriers' parents return on equity is rejected. *See* A/T-149. This is consistent with the conclusions below concerning capital structure where use of the Parent's capital structure is rejected.

¹⁰⁷ State witness Ives using a weighted cost of capital for the Carriers calculated collections and earnings as of 2005 to be \$5.64 billion Exs. SOA-8 at 43-44; SOA-13.

154. Conversely, the Carriers' proposed rate comes in at the lower end of the spectrum with a proposed risk-free earnings rate of United States Treasury securities. Carriers' IB at 120-21; Ex. ATC-113 at 44. This rate is simply too low and fails to take into account that the Carriers basically have failed to create a separate DR&R account and, thus, have had free rein to use the funds as they please. *See* Ex. ATC-113 at 38-39; Staff IB at 68-71; A/T IB at 76-77. Additionally, the Carriers did not invest these funds in these securities. The Carriers also fail to cite any precedent to support their rate and Dr. Kalt's testimony on this issue is not credible. Ex. ATC-113 at 42-44. In refuting Mr. Brown's and Mr. Grasso's "grossly exaggerated rates of return," Dr. Kalt takes issue with such a rate because it essentially requires the Carriers to participate in risky investments. *Id.* However, in light of the fact that there is no DR&R fund at all, it is disingenuous for Dr. Kalt to argue that the appropriate rate is that which "the prudent and rational" investor would take. *Id.* at 44; ATC-113 at 38-39. While the Carriers used the DR&R monies collected as they pleased, they should be required to recognize a reasonable return on such funds. The Carriers' overly conservative "risk-free" rate is also rejected.¹⁰⁸ Thus, the quandary here is to find a balance between the earnings rate of a risky investor and the conservative "risk-free" investor, and more importantly, one that is supported by Commission precedent.

155. Dr. Toof's DR&R calculation in Exhibit ATC-130 (as directed to be corrected below) is the most credible DR&R earnings calculation. First, Anadarko/Tesoro's calculation in Exhibit A/T-30 incorrectly uses the 12 percent Moody's Aa bond rating for the period 1985 through 2005 without adjusting the percentage for changes in subsequent years. Carriers' IB at 120; Ex. ATC 115 at 41. This failure to use actual amounts (the same criticism Anadarko/Tesoro had of the Carriers' DR&R Actual Collected amounts for the period 1977-1981 in their DR&R study) renders this study flawed.¹⁰⁹ Dr. Toof's Exhibit ATC-130 DR&R calculation uses the actual Moody's Aa bond rating for each year. Ex. ATC-115 at 45. Dr. Toof explained that Exhibit ATC-130 presents the results of substituting Moody's Aa rate for the risk-free rate. The record shows that Dr. Horst created the underlying TSM DR&R allowance schedule in the TSA assuming that the revenue stream would earn Moody's Aa bond yield to achieve the desired DR&R expense amount of \$872.1 million (in 1977 dollars).¹¹⁰ Exhibit ATC-130 is Dr. Toof's DR&R calculation using the actual

¹⁰⁸ Exhibit ATC-129 is based on the "risk-free" rate and is therefore rejected.

¹⁰⁹ A/T IB at 72 n 61.

¹¹⁰ ATC-115 at 32-33. Dr. Horst's analysis adheres to the depreciation factors included in Exhibit F to the 1985 Settlement Agreement. Mr. Horst also assumed that the cost of DR&R would increase by the Gross National Product (GNP) deflator. Additionally, Dr. Horst (back in 1985) for the period 1985 to 2015 fixed the inflation rate at 6 percent and estimated a Moody's Aa bond yield at 12 percent. Ex. ATC-115 at 33.

Moody's Aa bond rate.¹¹¹ In making this calculation, Dr. Toof started with the data from Dr. Horst and corrected Mr. Grasso's methodological and data errors.¹¹² It is found that use of the actual Moody's Aa bond rate for the years 1977-2005 is the most reasonable approach here. This is consistent with what Dr. Horst did in 1985 to reflect DR&R allowances in the TSA. However, since he was forecasting he presumed a 12% rate for future years. Now that the rates have actually been collected (including the DR&R allowances) consistent with his approach, the actual Moody Aa bond rates can be used to establish earnings on the DR&R funds. This is consistent with the approach utilized in the TSA and it is found that it is equitable to continue such an approach.

156. Anadarko/Tesoro claim that Dr. Toof's calculations do not reflect actual collections for the period 1977-1981.¹¹³ Anadarko/Tesoro are correct in that Dr. Toof replaces the TSM numbers with what he claims are the actual collections for this period. There is no evidence in this record to justify Dr. Toof's replacement numbers for this period. The Carriers claim that Mr. Grasso's calculation incorrectly includes the TSM-6 amounts that are not based on the amounts included in the TAPS Carriers' tariffs for the period 1977 through 1981. Carriers' IB at 119. This argument is rejected and it is found that the correct amounts are indeed found in the TSM-6. As discussed above, the evidence in the record clearly shows that TSM-6 was used to calculate the Carriers' revenue requirements and refund liabilities from the period from 1977- 1985 under the TSA. A/T-140 at 96; A/T-35 at 25, 107; A/T-44 at ln. 117 (TSM-6 data from 1968-2011); A/T-196 at 229-31, 236-37; Staff IB at 68; A/T-195 at ln. 117. The evidence shows that the amounts shown in Dr. Horst's schedule and used by Mr. Grasso reflect the amounts that were used to calculate the TSM revenue requirements and refunds for those years. A/T-140 at 100. Accordingly, the Carriers'

¹¹¹ ATC-130 is ATC-129 substituting the "risk free" rate for the Moody's Aa bond rate. ATC-115 at 45.

¹¹² Dr. Toof states that Mr. Grasso's errors are that he: (1) incorrectly used the DR&R amounts for the period 1977 to 1981 included in the Dr. Horst schedule which are not the actual amounts collected by the Carriers; (2) incorrectly computes the Carriers' tax saving over the period 1977 to 2003 (Dr. Toof states that it should only be from 1988 to 2003); (3) ignores that the Carriers have waived collection of the TSM DR&R allowance on intrastate throughput and did not include the short fall in the interstate revenue requirement and; (4) he incorrectly uses the 12 percent rate assumed by Dr. Horst in 1985 instead of the Moody's Aa bond yield for the period 1985 through 2005. *Id.* at 40-41.

¹¹³ Dr. Toof claims that he used the numbers used in the ICC filings. However, as discussed above, these numbers were not collected through the Carriers rates for TAPS for the years in question.

attempt to use the numbers they claim were in their initial ICC filings is rejected. Carriers' IB at 119-20; ATC-115 at 41.

157. Consequently, it is found that the record reflects that the TSM model numbers for these years should be used since this is what was actually collected in rates. Support for this is found in Dr. Toof's testimony at Ex. ATC-126 column titled "1985 TSM Model." These are the numbers used by Grasso for the same years. See Ex. A/T-149. These numbers are also corroborated by Ex. A/T-195. As a result, Dr. Toof's study will be corrected by replacing the TSM numbers in his "Adjusted DR&R Allowance" column, starting with 1977 through 1981 in Exhibit ATC-130.¹¹⁴ Thus for 1977-1981 the numbers found in Grasso's Ex. A/T-149 for DR&R allowances collected will be used. The results of this amended exhibit will be reported to the Commission in a compliance filing.

158. The evidence in the record supports a finding that the Carriers' weighted average nominal after tax cost of capital is the most reasonable rate for reflecting future earnings on DR&R monies already collected. Since a Carrier is presumed to eventually earn the weighted average nominal after tax cost of capital on rate base items a similar assumption can reasonably be applied here. Thus, it is found that from 2006 forward, the Carriers will calculate the earnings of the DR&R account using their weighted average nominal after tax cost of capital¹¹⁵ (with the adjustments from above as their starting point). Anadarko/Tesoro's argument is not moot since their argument has been addressed by the mandated adjustment above which modifies the 1977-1981 data to reflect the TSM amounts of DR&R for this period (found in Dr. Horst's TSM-6 schedule). A/T-44 at ln.117.

159. Accordingly, pursuant to the findings above, it is concluded that the amount of DR&R collections and earnings to date will be calculated using the methodology in ATC-130 (page 1 of 2) with the following modifications: (1) Exhibit ATC-130 shall be modified to replace the "Adjusted DR&R Allowance" for years 1977 through 1981 with the amounts from the "Actual" column in Exhibit ATC-126 (*see also* A/T 149 column "Actual DR&R Collections") for years 1977 through 1981 and (2) Exhibit ATC-130 "Moody's Aa" column shall be utilized to calculate the Carriers' after tax accumulated balance for the every year starting with 1977 thru 2005 and starting in

¹¹⁴ Exhibit ATC-130 shall be modified to replace the "Adjusted DR&R Allowance" for years 1977 through 1981 with the amounts from the 1985 TSM Model column in Exhibit ATC-126 (*see also* A/T 149 column "Actual DR&R Collections"). In other words, the DR&R numbers for 1977-1981 will be the numbers reflected in the TSM.

¹¹⁵ For clarity, this equals the addition of nominal weighted rate of return on equity and the weighted cost of debt.

2006 and forward, the earning on DR&R shall be calculated using the Carriers weighted average nominal after tax cost of capital. Thus, the funds collected will continue to earn at a reasonable rate consistent with this decision.

160. Anadarko/Tesoro and Staff argue that there should be no further collections for DR&R expense because: (1) the Carriers failed to support any DR&R allowance; (2) the Carriers have failed to account for amounts collected and associated earnings thus far; (3) the Carriers have already overcollected DR&R; and (4) basic assumptions underlying the original DR&R schedule have changed. Anadarko Tesoro and Staff are correct that the Carriers have failed to make a showing, *prima facie* or otherwise, that further DR&R collections are required. See Staff IB at 66-70; A/T IB at 75-77. Further corroboration of this is that the Carriers failed to include DR&R in their Opinion 154-B presentation and Dr. Toof and Mr. Van Hoecke only offer terse DR&R discussions that also fail to support any further DR&R collections.¹¹⁶ In addition, although Mr. Browning provides extensive testimony regarding his DR&R cost estimates, the Carriers fail to show that they still have not collected sufficient DR&R to cover the estimated amount. See ATC-157 (Browning). Thus, it is found that the Carriers have not cost justified additional collections of DR&R expense through future rates and, accordingly, the expense is not permitted to be collected in the cost based 2005 and 2006 Carriers' rates. This is consistent with Commission policy.¹¹⁷

Rate Base Credit

161. Anadarko/Tesoro and Staff contend that a portion of the amount collected should be credited to rate base or refunded because the Carriers have amassed "a DR&R fund that is enormous" and "far outstrips anyone's estimate of what the eventual DR&R task will require." Staff IB 64, 90-94; A/T IB at 106-10. Anadarko/Tesoro and Staff advocate a rate base credit for DR&R while Flint Hills and the Carriers vehemently oppose such a credit. Anadarko/Tesoro and Staff cite

¹¹⁶ Staff IB at 70; A/T IB at 75; ATC-12 at 27, 29 (Dr. Toof's mention of DR&R expense only includes a reference to the stipulated DR&R allowance in the TSM); ATC-35 at 33 (Van Hoecke simply states that that he did not include any DR&R in his Opinion 154-B analysis). An inference is made that the Carriers deemed they did not need to collect any additional DR&R in costs based rates. This is distinguishable from their rate filings for 2005 and 2006 which included an allowance for DR&R. Ex. ATC-12 at 27, §II.D.10. Dr. Toof acknowledges that the TAPS TSA revenue requirement included an allowance for DR&R but the Carriers did not support such under their 154-B proxy.

¹¹⁷ See *Sabine River Authority*, 10 FERC ¶ 61,241 at 61,451 (1980); *FPC v. Natural Gas Pipeline Co.*, 315 U. S. 593-96.

Kuparuk in support of the proposition that the Carriers must credit rate base so that the Carriers do not “reap the time value of these funds without compensating rate payers” and to “eliminate the contentious issue of the interest rate at which DR&R funds will grow in the future.”¹¹⁸ The rate base in this case is \$576.86 million. The remaining rate base in TAPS will be fully depreciated by 2011. Tr. 2685 (Van Hoecke). However, Strategic Reconfiguration will add some rate base as it is built. Anadarko/Tesoro argue that only a portion of the DR&R be credited against rate base. Essentially, crediting rate base would zero it out. The Carriers have effectively distinguished *Kuparuk* from this case by pointing out that in *Kuparuk*, the Commission adopted an accrual methodology for DR&R amounts, while the DR&R here was collected based on the annuity method. *Kuparuk*, 55 FERC at 61,382; Ex. ATC-115 at 33.¹¹⁹

162. Noting the impact of this difference is critical. The accrual method takes the total amount of the estimated DR&R expense and divides it into equal payments to be made by the shippers. Tr. 4959. Whereas, under the annuity method, the shippers do not pay the full amount, but some lesser amount which is expected to grow over time to cover the total expense. Tr. 4959-60; Carriers IB at 69; RB at 53-54; Tr.6669. Crediting the rate base for the amounts of collected DR&R under the annuity method would prevent the Carriers from earning the interest on those funds that is to be added to the DR&R “fund” to cover the final DR&R costs.¹²⁰ Unlike the instant case in *Kuparuk* the DR&R did not exceed the rate base. Moreover, the earnings in the instant case have been earning interest for years. Whereas, in *Kuparuk* the issue was whether the accruing funds should be deducted from rate base rather than from the rate of return.

163. In addition, the other cases cited by Anadarko/Tesoro and Staff for the proposition of crediting rate base are distinguishable.¹²¹ Staff points out correctly

¹¹⁸ Staff IB at 63; A/T IB at 71.

¹¹⁹ Carriers IB at 69-70; RB at 53-54.

¹²⁰ It is noted that in *Kuparuk* the Commission was setting rates close to the beginning of service on the pipeline. This is not the case here were we are looking backwards to establish the remaining rate base and looking forward to establish cost based rates under Opinion 154-B which has never been followed to set rates on TAPS.

¹²¹ Staff IB at 63 n. 90 (*Kansas Pipeline Co.*, 96 FERC ¶ 63,014 at 65,100-01 (2001); *ARCO Pipe Line Co.*, 52 FERC ¶ 61,055 at 61,238 (1990).; A/T IB at 71 n.60 (citing *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 289-95 (2002); *Koch Gateway Pipeline Co.*, 79 FERC ¶ 61,388 at 62,648 (1997); *Williston Basin*, 72 FERC at 61,365; *Endicott Pipeline Co.*, 55 FERC ¶ 63,028 at 62,648 (1991); *Tennessee Gas Pipeline Co.*, 25 FERC ¶ 63,052 at 65,153 (1983), *aff'd in part*, 32 FERC ¶ 61,086 at

that the instant case is different from any cited case. This is because the DR&R collections began early in the TAPS line, in front-loaded amounts contrary to any Commission precedent. The fund outstrips the TAPS current rate base and probably what the eventual DR&R task will require.¹²² It is the Carriers who, admittedly, will bear the obligation of paying for the DR&R of TAPS, regardless of the final cost.¹²³ As discussed above, the final amount of DR&R costs is speculative at this point. Thus, it is concluded that at this time the Carriers will not be required to credit rate base or refund any amounts.

164. The Carriers' arguments that refunds or a rate base credit amount to retroactive rate making or a taking are rendered moot by this finding. Flint Hills' arguments concerning the rate base credit are also moot. Finally, Flint Hills' request that a refund for one-half of the DR&R collected be given to past shippers in the interest of intergenerational equity is also denied due to the unsettled nature of the final DR&R cost issue. The conclusions here synchronize the DR&R balances retained by the Carriers with the expected expense level. This is a reasonable approach which protects rate payers under the circumstances of this case.

Other Remedies

165. Staff and Anadarko/Tesoro correctly classify the DR&R collections and earnings as a prepayment. Staff IB at 93; A/T IB at 71; Tr.5507-08. The shippers' payment of DR&R is indeed a prepayment of an expense that may be refundable in the event that there is a surplus once the DR&R is completed. *See Kuparuk*, 55 FERC at 61,382.

61,220 (1985)). The various cases do stand for the proposition that DR&R should be credited to rate base because the pipeline is assumed to recover the full amount of its costs from the ratepayers and any interest is considered an excess (or compensation). However, in the case at bar the amounts collected and the interest earned become part of the DR&R expense "fund" which are necessary to meet the future total costs. The collections plus the interest earned are needed to meet the total DR&R expense. This is the reality of what the TSA parties agreed to early in the life of TAPS. Moreover in this regard, the shippers have been paying less as a result of this methodology.

¹²² Staff IB at 64.

¹²³ Dr. Toof stated that "[i]t is certainly my testimony that TAPS carriers and their parents have unlimited liability to do the DR&R remediation... if the TSM ran through 2011 to its conclusion, absent extraordinary events that the TAPS Carriers would have the total liability and collected all the DR&R they could collect." Tr. 655. ATC-113 at 38 ("What stands behind the ultimate DR&R expenditures are the TAPS Carriers, themselves, and the parent company guarantees that the Secretary of the Interior has required under the Federal Right-of-Way grant").

166. The Carriers' argument that they should not be required to account for DR&R is rejected. The record in this case shows that in fact they have collected DR&R in rates for almost three decades. Importantly, the Carriers admit that there is no "stand-alone" DR&R fund maintained by the TAPS Carriers." Ex. ATC-115 at 33:1-2. Thus, although these arguments were presented to support denying further DR&R collections, they provide additional support for the requirement that the Carriers account for the funds collected.

167. Accordingly, the Carriers will be required to account for the DR&R funds collected and the earnings on such funds. Thus, it is concluded that the Carriers will be required to maintain an accounting of the DR&R and earnings to date using the methodology prescribed above and report such amounts on Form 6 on a yearly basis.¹²⁴ These reports will utilize the amounts from the corrected Ex. ATC-130 up to 2005. Starting in 2006 the annual reports shall show the sums credited yearly to DR&R earnings based on the Carriers' weighted average nominal after tax cost of capital.

168. The Carriers' argument that requiring them to maintain an accounting of their DR&R collections and earnings constitutes retroactive ratemaking is meritless. Staff and Anadarko/Tesoro are correct. The case cited by the Carriers is distinguished and there is no retroactive ratemaking issue here where the money was collected in jurisdictional rates and related to a jurisdictional service such as the TAPS pipeline.¹²⁵ In addition, there are no retroactive ratemaking implications where the remedy is only forward looking, such as the accounting requirement imposed here.¹²⁶ Requiring an

¹²⁴ In *Kuparuk*, *supra* the Commission required an internal accounting for DR&R and details in annual reports of the sums credited to the DR&R fund. *Kuparuk*, 55 FERC at 61,382.

¹²⁵ The case cited by the Carriers is distinguishable. The Carriers cite, *Public Utilities Commission of California v. FERC*, 894 F.2d 1372 (D.C. Cir. 1990) (*California*), for the proposition that requiring refunds, a rate base credit, or an accounting related to DR&R refunds constitute retroactive ratemaking. Staff and Anadarko/Tesoro correctly point out that in *California* the deferred tax reserve had been collected in jurisdictional rates and the rate base credit would have been to non-jurisdictional assets. 894 F.2d at 1380. The court's concern there was that the Commission's credit for the funds collected was "not attached to, derived from, or related to" the service. *Id.* at 1379. In contrast, here there is no matching issue since "the DR&R funds were collected in jurisdictional rates and relate to the jurisdictional TAPS pipeline." A/T RB at 89.

¹²⁶ The Carriers cite *Tarpon Transmission Co.*, 57 FERC P 61,371 (1991), to support their argument that the Commission lacks authority to return overrecoveries

accounting of DR&R collections and earnings is wholly consistent with Commission precedent.¹²⁷ DR&R collections are for an anticipated expense that may need to be refunded to the shippers in the event there is a surplus. Flint Hills' requested remedy is also denied due to the speculative nature of the actual DR&R expenses at this time and up to the time the Carriers have to undertake the dismantlement. In addition, as Staff points out, granting the refund contemplated by Flint Hills will be a monumental task that, if undertaken at all, should be when all final costs are known. *See* Staff RB at 87 n.285.

169. In conclusion, it is found that while the question of the ultimate cost of DR&R lingers, the question of whether refunds are necessary is premature. The Carriers will not be required to credit rate base or refund any DR&R at this point. However, the Carriers will be required to maintain an accounting of the DR&R amounts collected and returns on such amounts in their Form 6 report as described above.

Issue III. F. What is the appropriate return on investment?

1. The Carriers claim that the cost of capital should be based on the capital structure of the Carriers' parent companies, the parents' companies cost of debt, and a cost of equity established using the DCF methodology with oil pipeline proxy companies or using a risk premium methodology if appropriate oil pipeline proxy companies are unavailable. Additionally, the Carriers argue that they should get a two percentage point equity risk premium to reflect the extraordinary risks associated with TAPS.

Issue III. F. 1. What is the appropriate capital structure?

170. The Carriers and Flint Hill claim, the appropriate capital structure to be used by each TAPS Carrier is the actual capital structure of its parent company. The Carriers assert that in Opinion 154-B, the Commission required oil pipelines to use actual rather than hypothetical capital structures of either the pipeline or its parent. Carriers' IB at 74 (citing Opinion 154-B, 31 FERC at 61,836). In addition, the Carriers claim that the Commission also held that a pipeline should use its parent's

to ratepayers. This case is inapplicable since the accounting requirement only concerns the 2005 rates forward. In addition, Anadarko/Tesoro cite Tarpon to argue that a surplus must be refunded to ratepayers. As discussed above this request has been denied as premature.

¹²⁷ *See Kuparuk*, 55 FERC at 61,382; *see Sepulveda*, 117 FERC at P 74-75 (The Commission required SFPP to provide an accounting of "regulatory costs outstanding at the beginning and end of each year and the amount of those costs recovered during each year.").

actual capital structure if the pipeline has issued no long-term debt, has issued long-term debt to its parent, or has issued long-term debt to outside investors guaranteed by its parent. That is the case here, the Carriers claim. The Carriers also assert that the Commission has approved the use of pipeline's parent company's capital structure in each oil pipeline filing it has considered and never imposed a hypothetical capital structure on an oil pipeline.¹²⁸ Moreover, the Carriers add that the 71.42% equity ratio that represents the ownership weighted average equity ratio for the TAPS Carriers' parents from 1968 through 2005 is similar to the 71% equity ratio allowed in *Colonial*.

171. The Carriers state that the ICC and the Commission have recognized that the TAPS project produces a higher risk factor than is normal in crude oil operations and that at one point there was a risk that TAPS would not be completed due to cost overruns.¹²⁹ The Carriers claim that these risks had a substantial impact on the financing of TAPS that was so significant that TAPS could not have been financed without the full backing of the TAPS Carriers' parent companies. Therefore, the Carriers contend, it is appropriate that the TAPS Carriers' rates be based on the parent companies' capital structures. This will reflect the capital structure underlying the investment, the Carriers assert.

172. Further, the Carriers claim that the parent companies are vertically integrated, highly diversified oil companies that engage in numerous businesses that have offsetting risks. This is also confirmed by the parent companies' Form 10-K Annual Reports to the SEC, the Carriers claim. In contrast, the Carriers state that they are much less diversified and they have a single asset, in a single location, dependent upon production from one area—the TAPS pipeline. These differences make the business of the TAPS Carriers riskier than the businesses of their parent companies, the Carriers contend. Thus, the Carriers conclude both Commission precedent and the

¹²⁸ The Carriers cite *Kuparuk, supra* and *Colonial Pipeline Co.*, 116 FERC ¶ 61,078 at P 62 (2006) (*Colonial*)(constitutes provisional acceptance of an equity ratio as high as 71%).

¹²⁹ The Carriers state that these risks include the concentration of TAPS assets in Alaska, the hostility of the Alaskan terrain and weather, the environmental and technical challenges faced by the Carriers in designing, constructing, etc. TAPS, the continuing sensitivity of various state and federal government authorities, the stringent legal requirements imposed on TAPS, the number of time consuming delays caused by the need to obtain multiple approvals from state and federal authorities, the enormous capital investment ultimately required to construct TAPS, the need for investors to fund the entire \$9.1 billion project before TAPS could generate any revenue to return to investors, and sabotage.

facts of this case which show that the Carriers' business is more risky than that of the parent companies supports the use of the parent companies' capital structures.

173. The Carriers claim that the capital structure used by the State's and Anadarko/Tesoro's proxy group is inappropriate. First, the Carriers argue that the use of a proxy group to determine the capital structure of an oil pipeline company is unprecedented. The Carriers state that the Commission uses a proxy when applying the DCF methodology to determine the cost of equity. However, Anadarko/Tesoro and the State take the unprecedented approach of using their proxy group as a measure of capital structure in an oil pipeline case. Second, the Carriers assert that the proxy group companies face lower risks than the Carriers because those businesses acquired a ready built pipelines and have diversified businesses. Third, the Carriers contend that the proxy group companies' capital structures are not all comparable to the capital structures of oil pipeline companies. Fourth, the proxy companies do not have oil pipeline operations in Alaska, and therefore these companies are not subject to the risks associated with the extreme climate and harsh terrain as is TAPS. Fifth, the Carriers argue that determination of a capital structure is not an exact science and involves other factors such as the need for funds and the ability to raise debt. Sixth, the Carriers claim that the capital structure proposed by Anadarko/Tesoro and the State would eliminate the Carriers' ability to raise any debt because the cash flow generated from rates would be insufficient. Finally, the Carriers contend that the bond rating of the DCF proxy group members is just above junk bond status and the suggested proxy structures would cause the Carriers to be on the verge of junk bond status.

174. Next, Flint Hills argues that the oil pipelines cannot be used to establish capital structures in this proceeding. Flint Hills claims that in *Sepulveda*, 117 FERC at 62,376, the Commission rejected the use of the sixth member of the oil pipeline proxy group (Enron Liquids) because its distributions per unit exceeded per unit income in each of the years. In *Sepulveda*, the Commission held that MLPs cannot be used as proxy companies for return on equity if distributions exceed earnings, Flint Hills claims. Flint Hills asserts that during the cross-examination of Mr. Henley it was established that all four of the remaining oil pipeline MLP proxies now have distributions per unit that exceed income per unit for the relevant time periods. In addition, Flint Hills states that Mr. Hanley agreed that based on *Sepulveda*, there was the potential that each of the MLPs might be disqualified for use in an oil proxy to establish capital structures for oil pipelines. Flint Hills claims that Anadarko/Tesoro ignored this decision.

175. Flint Hills also argues that there is no basis for using gas pipeline proxies because in Opinion No. 435, the Commission found that the use of gas companies in proxy groups for oil pipelines was no longer necessary and that using gas pipelines as a proxy for data that was not readily available no longer has to control. Since the

proxy group cannot be used, Flint Hills claims, the only other option is to use the TAPS Carriers' parent's weighted average capital structure. Flint Hills claims that Staff's assertion that all of the parties have constructively agreed to use the same MLP proxy group and that the Commission could accept that agreement as a trial stipulation is preposterous. Flint Hills states that the proposition is flawed because it is likely that not all of the parties (or none of the parties) would have used an oil pipeline proxy group if SPFF Sepulveda would have been issued before testimony was filed and Flint Hills has never agreed to use the oil pipeline MLP proxy group. In addition, Flint Hills states that Anadarko/Tesoro also claim that earnings-capped distributions could be used in the DCF calculation. This approach was rejected in *Kern River*, Flint Hills contends. Thus Flint Hills concludes, the parent company capital structures should be used for return and deferred earnings purposes. Alternatively, Flint Hills argues that the record must be supplemented for cost of equity purposes.

176. Flint Hills claims that no Commission authority exists to use gas pipeline proxies in this proceeding. Staff suggests the use of a gas pipeline proxy group as an alternative, Flint Hills claims. Flint Hills states that Staff supports this proposition by citing *SFPP L.P.* which stated that the Commission used to rely on gas pipelines as a proxy. Flint Hills asserts that since this evidence is no longer available, it is inappropriate to go back to using gas pipelines as a proxy. In addition, Flint Hills claims that Anadarko/Tesoro witness Mr. Hanley did include an analysis using gas pipelines. However, Flint Hills claims, Mr. Hanley made it clear that he had not included the gas pipeline proxy as a recommended basis for determining the capital structure of TAPS or as a substitute for the four oil pipeline MLPs. Finally, Flint Hills states that no party's rate of return witness was on notice with respect to the possible problem with the use of oil pipeline MLP proxies prior to filing written testimony and therefore none of the witnesses addressed the problem or other avenues to address the issue. If any of these issues, including using the proposed oil pipeline MLP proxies are to be considered in the Initial Decision, in light of the *Sepulveda* decision, the hearing in this proceeding would have to be reopened so that additional pre-filed testimony could be submitted and witnesses cross-examined, Flint Hills claims. Flint Hills states that this can be avoided if the parents' weighted average capital structure is used.

177. Anadarko/Tesoro state that the appropriate capital structure for TAPS for 2005 is 55% debt/45% equity and for 2006, 58% debt/42% equity per the evidence sponsored by Mr. Hanley. Anadarko/Tesoro claim that the Carriers' capital structures are inappropriate because the parents have unusually high equity ratios.¹³⁰

¹³⁰ Anadarko/Tesoro state that the Carriers propose capital structures for each of the Carriers while Anadarko/Tesoro propose only one overall capital structure.

Anadarko/Tesoro state that their study focuses on the cost of capital for 2005 and 2006 while the Carriers have attempted to reconstruct capital structures, equity costs and debt costs back to 1984. First, Commission precedent requires the rejection of "anomalous" capital structures, Anadarko/Tesoro contend. Specifically, Anadarko/Tesoro argue that where the regulated entity does not provide its own financing, the Commission uses either the capital structure of the regulated entity's parent or a hypothetical capital structure. Anadarko/Tesoro assert that the Commission has recognized that typical equity ratios are in the range of 45%-55%.

178. Second, Anadarko/Tesoro argue that the Carrier's equity-rich capital structure with an equity ratio as high as 87 percent or 85 percent is unprecedented and unsupported by case law. Anadarko/Tesoro claim that the Carriers structures are anomalous as compared to both Commission precedent and the DCF calculations. In fact, Anadarko/Tesoro claim, the Carriers' witness Prof. Williams confirmed that equity ratios as high as those proposed by the Carriers (85% for 2005, 87% for 2006) have never been approved by the Commission. In addition, Anadarko/Tesoro state that nothing cited by Flint Hills supports the Carriers' unreasonable capital structures. Anadarko/Tesoro also assert that the equity structures proposed by the Carriers are also anomalous when compared to the proxy group used by all the parties for the DCF calculation (including the Carriers). The Carriers' use of an equity rich structure is not justified by the risk associated with TAPS, Anadarko/Tesoro assert. Anadarko/Tesoro claim that the original risks associated with TAPS are irrelevant for setting current rates. According to Anadarko/Tesoro, the Carriers do not have greater risks than their parent companies that participate in the risky world-wide business of oil and gas exploration and production (E&P).

179. Anadarko/Tesoro claim that the cases cited by the Carriers are inapposite. The first case, *Colonial*, is simply a declaratory order and does not reach any just and reasonable findings or approve any specific rate of recovery and was conditional subject to reexamination in the pipeline's next rate proceeding, Anadarko/Tesoro claim. Anadarko/Tesoro assert that the 71% equity ratio in *Colonial* was described as the extreme of what the commission has approved and provides no basis for the Carriers proposed 87%. The second case Anadarko/Tesoro assert, does not support the Carriers 87% equity ratio because in *Kuparuk*, the Commission rejected the use of the parent's 70% equity ratio. Anadarko/Tesoro also argue that the cases cited by Flint Hills were subsequently distinguished by the Commission and do not support the use of their proposed 71.46% equity ratio.¹³¹ Thus, Anadarko/Tesoro conclude, the Carriers proposed parent-based capital structures are unjust and unreasonable and a proxy-based capital structure should be used.

¹³¹ See FHR IB at 34 (citing *Midwestern Gas Transmission Company*, 31 FERC ¶ 61,317; *Alabama-Tennessee Natural Gas Co.*, 13 FERC ¶ 61,224; A/T RB at 65 (citing *Alabama-Tennessee Natural Gas Co.*, 40 FERC ¶ 61,244 at 61,814).

180. Anadarko/Tesoro claim that their proxy-based capital structure, sponsored by Mr. Hanley, is supported by substantial record evidence and Commission precedent. Anadarko/Tesoro state that this is the only hypothetical that is supported by substantial evidence in the record. Mr. Hanley's capital structure was supported by the State, Anadarko/Tesoro contend. Moreover, Anadarko/Tesoro assert, the Carriers' witness Mr. Williamson used the same proxy group for his test period DCF analysis. According to Anadarko/Tesoro, the Carriers claim that Mr. Hanley's proxy group is appropriate for determining the DCF-based cost of equity for TAPS, but not for determining capital structures. Anadarko/Tesoro state that the Carriers' arguments that the use of a proxy group capital structure is unprecedented for an oil pipeline, is not reflective of the operation and business risks of TAPS, is not representative of the capital structures of other Alaskan oil pipelines, and would impair the Carriers' ability to raise capital. These claims have been addressed by the showing that the parent-based capital structures are unjust and unreasonable and that the Commission's policy is to reject parent-based capital structures that are anomalous or unrepresentative of the pipeline's risks, Anadarko/Tesoro claim. Furthermore, Anadarko/Tesoro state that the Commission has adopted hypothetical capital structures for regulated pipelines in order to mitigate the effects on ratepayers of paying abnormally high equity ratios.

181. Anadarko/Tesoro also assert that the Commission has never approved a capital structure anywhere close to the 100% equity ratio suggested by Professor Williams. The Carriers claim that the equity ratio in Kuparuk is instructive here, Anadarko/Tesoro contend. Anadarko/Tesoro state that contrary to the Carriers' position, Anadarko/Tesoro's equity ratio of 45% for 2005 and 42% for 2006 are closer to Kuparuk's 57% equity ratio than the Carriers' 85% for 2005 and 87% for 2006. Anadarko/Tesoro also state that unlike TAPS the Kuparuk system is anchored by a single small supply source and has historically faced throughput risks; however, the Carriers still argue that Kuparuk was less risky than the proxy companies used in the DCF calculation.

182. Anadarko/Tesoro also state that Flint Hills' argue that Master Limited Partnerships (MLPs) should not be used as proxy companies to determine the TAPS capital structure, to the extent that MLP distributions exceed earnings. However, Anadarko/Tesoro claim, that the distribution vs. dividend distinction only arises in the context of calculating equity returns under the DCF analysis and has never been cited by the Commission as a relevant consideration in the determination of an entity's capital structure. Anadarko/Tesoro also state that the Carriers' concerns about the ability to raise capital under Mr. Hanley's capital structure are without merit since the evidence cited by the Carriers to support these claims was discredited at the hearing.

183. Staff states that since TAPS does not provide its own debt financing all the parties have proposed an alternative. The Carriers' proposal to use the capital

structure of each parent presents the kind of "anomalous" situation the Commission wants to avoid, Staff asserts. The Carriers' proposal averages about 85% equity and 15% debt and does not reflect the risk of the Carriers and it is not similar to the capital structures allowed for other oil pipelines. The proxy group used by Anadarko/Tesoro and the State are based on a hypothetical proxy group that is identical to a typical oil pipeline. Staff states that this is the same hypothetical proxy group used in *SFPP, L.P.*, 69 FERC P 61,279. The applicability of the proxy group used by Anadarko/Tesoro and the State was shown through an empirical study which showed the risk profile of TAPS was comparable to that of the oil pipeline proxy group and Mr. Hanley's alternative gas pipeline proxy group.

184. Staff states that the only potential problem is that all of the members of Anadarko/Tesoro's and the State's proxy group are MLPs. In *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043 (2005), *order on reh'g*, 112 FERC ¶61,050 (200), *order on reh'g*, 113 FERC ¶ 61,280 (2005) (*HIOS*), the Commission excluded MLPs from the proxy group used to determine a jurisdictional partnership's equity cost unless the distributions by the MLPs have the same characteristics as a corporate dividend. Additionally, Staff states that *Sepulveda*, 117 FERC ¶ 61,285, addressed the use of MLPs in the same equity proxy group and determined it was flawed.¹³² Staff states that the Carriers' parents are highly-diversified and different companies than their regulated pipeline subsidiaries (the Carriers). The parents do not represent the same risk profile as the Carriers and are therefore anomalous for capital structure purposes, Staff argues. In addition, Staff states that whatever proxy group is adopted for equity purposes should also be used for capital structure purposes.

185. Staff's reply brief also states that Anadarko/Tesoro and the State rely on the average capital structure derived from the same proxy group they used to determine ROE. This "matching" of proxy groups for purposes of return on equity and capital structure is both rational¹³³ and consistent with Commission precedent. According to Staff, the Carriers' request to use the capital structures of their parent companies, but never actually state what those equity/debt ratios are in their initial brief. Staff suggests that this is because the result is an 85% equity ratio for base year 2004 and 87% equity ratio for base year 2005 which is higher than any ratio ever approved by the Commission. Staff states that in light of the Commission's requirements, the Carriers' proposed equity structure cannot be accepted. Staff claims that all the parties that presented ROE evidence used the identical proxy group in their DCF

¹³² Staff also cites *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 (2006) (Opinion No. 486).

¹³³ Staff states that this "matching" is rational because since the ROE and capital structure are supposed to reflect the level of financial risk, it makes sense that they both reflect a similar financial risk. Staff RB at 52.

calculations, but the Carriers refuse to use Anadarko/Tesoro's and Staff's proxy group for the capital structure. Staff states that the Carriers' refusal to match the proxies, and thus, the risks used to determine both ROE and capital structure, makes the Carriers' proposal anomalous and it should be rejected by the Commission.

186. Staff also states that the Carriers' attempt to cite *Colonial* to support their high equity ratio fails for a number of reasons. Staff asserts that the State claims that *Colonial* does not apply to this case because: (1) the Commission never in fact approved the proposed 71% equity ratio as just and reasonable, (2) the order only mentioned the proposal to note that it was "at the extreme" of anything approved in the past, (3) the order pledged to review the proposal upon completion of the project based upon *Colonial*'s circumstances and Commission precedent at the time, (4) the proposal concerned financing for an expansion project yet to be built, not a thirty-year old pipeline with a successful operating and earnings history, and (5) the order was not premised on any evidence in a litigated record. Staff RB at 55, State IB at 51-52. Staff claims that *Kuparuk* is also distinguishable because the 58% equity ratio approved in *Kuparuk* is nowhere near the 85-87% proposed by the Carriers. Staff claims that the 58% approved for *Kuparuk* is still too high for TAPS because *Kuparuk* faces additional risks that TAPS does not encounter today. Staff RB at 55, *Kuparuk*, at 55 FERC at 61,378. Finally Staff states that the Carriers' criticisms of Anadarko/Tesoro's proxy capital structure are unfounded.

187. The Carriers' arguments concerning the operating, economic, and regulatory risks of TAPS is unconvincing, Staff claims. Contrary to the Carriers' contentions, Staff states that the fact that all of the TAPS assets are in Alaska is no different from any other pipeline that is tied to a specific field and location. Staff further notes that the proven reserves are enormous, most of the volumes are shipped by the Carriers' affiliated producers that help assure consistent throughput and revenues, the hostile Alaskan terrain is not unusual as many oil pipelines operate in hostile environments. In addition, Staff states that the scrutiny of the State and Federal authorities over TAPS operations suggests that TAPS is a safer operation. Staff also asserts that diversification may reduce risk; however, there is no evidence showing that diversification among risky projects results in overall low risk as suggested by the Carriers.

Discussion/Findings

188. The appropriate capital structure is an integral part of any return calculation. Staff IB at 70. In calculating the rate of return, the first step in the process is to determine the appropriate capital structure which consists of the appropriate debt and equity percentages. *A/T-4* at 2. The capital structure of an entity should also be commensurate with the business risks of the enterprise. *Id.*; *SFPP L.P.*, 96 FERC at 62,066. In addition, the capital structure should not be based on the parent company's

capital structure unless the parent company's business risks are equivalent to those of an operating oil pipeline. *Id.* The Commission will usually use the capital structure of the regulated entity unless it does not provide its own financing, in which case, the Commission will look to the parent company. Staff IB at 71; *Entrega*, 113 FERC at P 32. The Commission, in Opinion 435-B 96 FERC at 62,066, stated that there is a strong presumption in favor of using the parent company's capital structure. Staff IB at 71; see *ARCO Pipeline Company*, 52 FERC ¶61,055 (1990) at 61,233 (*ARCO*). However, if the Commission finds that the parent company's capital structure is "anomalous relative to the capital structures of the publicly-traded proxy companies used in the DCF analysis and capital structures approved for other regulated pipelines," the Commission will use a hypothetical capital structure.¹³⁴ In addition, Opinion 154-B states that "the Commission shall use a pipeline's or its parent's actual capital structure, but will allow participants on a case-specific basis to urge the use of some other capital structure." 31 FERC at 61,833.

189. None of the TAPS Carriers issues debt without guarantees by the parent.¹³⁵ Ex. ATC-45 at 5; ATC-56 at 42-43. Thus, in cases such as this where the regulated entity has no debt of its own, the next step is to look to the capital structure of the Carriers' parents. See *SFPP, L.P.*, 96 FERC at 62,067. The Carriers' parents' capital structure is inappropriate because: (1) it falls well outside the range of capital structures normally approved by the Commission and (2) does not reflect the risks faced by the Carriers. First, the Carriers' proposal to use the weighted average equity ratio of the parent companies for the period 1968-2005 (71.42%) is rejected since no support can be found in Commission precedent or the record to support the use of such a high ratio.¹³⁶ The Carriers cite *Colonial* and *Kuparuk* in support of their 71.42% equity ratio; however, those cases simply do not support the Carriers' claim.

190. The Carriers argue that the Commission accepted a 71% equity ratio in *Colonial*. 116 FERC at P 59, 61-62, 65; Carriers' IB at 59. However, *Colonial* does

¹³⁴ Staff RB at 53 (quoting *Entrega*, 113 FERC at P 32); A/T IB at 79. Although as the Carriers argue, *SFPP, L.P.* did not impose a hypothetical capital structure on the pipeline, this case does, however, stand for the proposition that the Commission will impose a hypothetical capital structure where the capital structure is "clearly contrived, and...its financial risk [is] clearly different from that of its parents." 96 FERC at 62,068.

¹³⁵ Carriers' IB at 74 n.68.

¹³⁶ See *Entrega Gas Pipeline Inc.*, 113 FERC ¶ 61,327 at P 32 (2005) (*Entrega*) (65% equity); *ARCO Pipeline Co.*, 52 FERC ¶ 61,055 at 61,243 (1990) (*ARCO*) (44.12% equity); *Transcon. Gas Pipeline Corp.*, 84 FERC ¶ 61,084 (1998) (*Transcon*) (57.58% equity); *Mobile Oil Corp., v. SFPP, L.P.*, 96 FERC ¶ 61,281 at 62,068 (2001) (*SFPP, L.P.*) (39.26%).

not support the Carriers proposals. In Colonial the Commission never accepted the proposed 71% equity ratio as just and reasonable stating that such a ratio is "at the extreme of what [the Commission has] approved in the past," "toward the upper end of the zone of reasonableness." The Colonial order stated it would reverse the proposal upon completion of the project. The order was based on several factors that applied to Colonial, but do not apply to the Carriers. *See id.* at P 62. Colonial was embarking on a proposed mainline pipeline expansion that the Commission recognized was going to present "substantial challenges" such as the length and scope of the project, enormous investment involved, financing challenges, the challenges of constructing a multi-state project, and the short time for completion of the project. *Id.* at 59. As discussed more below, the Carriers are not facing such risks since TAPS is complete and the Carriers have no further need to raise funds for construction. Thus, the risks facing Colonial are not analogous to those facing the Carriers and therefore Colonial does not support granting the Carriers an equity ratio "toward the upper end of the zone of reasonableness." *See id.* Moreover, the Colonial order (a declaratory order) was not premised on a litigated record unlike the instant case.

191. *Kuparuk* also fails to lend support to the Carriers' proposed equity ratio. First, as Anadarko/Tesoro point out, the 57.8% equity ratio approved in *Kuparuk* simply cannot be read to support the Carriers' much higher proposal of 71.42% (87% according to Anadarko/Tesoro and 85% according to Staff). A/T RB at 61; Carriers' IB at 75-76; Staff IB at 74. The Carriers also state that in *Kuparuk*, the Commission reversed the initial decision's refusal to use the parent companies' capital structure because the initial decision's "analysis [did] not overcome the strong preference in Opinion 154-B for the use of a parent company's capital structure if the parent guarantees the oil pipeline's external debt." Carriers' IB (quoting *Kuparuk*, 55 FERC at 61,377). However, in *Kuparuk* the Commission rejected use of the parent's 70% equity ratio for 1984. *Id.* at 61,378. In *Kuparuk* the Commission noted risks in *Kuparuk* then that do not apply to TAPS. The risks in *Kuparuk* are not present in TAPS and as a result it is concluded that the 58% equity ratio approved there is too high for TAPS. *Kuparuk*, does not support the Carriers' contentions because there is substantial evidence in the record to support a finding that the Carriers' risks are not at all comparable to the risks of their parent companies.

192. Second, the record shows that the Carriers' parents' risks are simply not representative of the Carriers' risks. The Carriers' parents are involved in various highly risky and competitive world-wide E&P undertakings.¹³⁷ E&P is "an intensely

¹³⁷ A/T IB at 81-82; Staff RB at 55-59. *See Ex. A/T-205* at 5 (S&P Report Table 2 listing all of the Carriers' parents as comparable E&P companies, except for Koch which is not publicly traded and only has a 3% ownership interest in TAPS.); Tr. 1419-20; Ex. ATC-1 at 5; A/T-206 at FS-2; Exs. A/T 207-209. *See also* Hanley, Ex. A/T-53 at 8-9; A/T-59. The parent's earnings are derived mostly from E&P from

competitive, capital intensive, volatile, and cyclical industry.” Ex. A/T-205 at 6. Conversely, the Carriers are solely engaged in the TAPS pipeline monopoly with little remaining unrecovered investment.¹³⁸ More specifically, the evidence in the record shows the following: (1) TAPS has no direct competition and it is extremely unlikely that TAPS will face competition from another pipeline in the future¹³⁹; (2) there is “no alternate means of transporting crude oil out of Prudhoe Bay” and “revenues will be generated by the Pipeline Companies as long as Prudhoe Bay crude oil is being marketed,” Ex. A/T-160 at 26; Ex. A/T 169; (3) “the likelihood that additional reserves would be found was high and proved to be true,” Ex. A/T-100 at 26; and (4) there remains no competition for getting ANS oil to market and the threat of interruption is no greater than average, *id.* In addition, TAPS has “an impressive safety and reliability record” so there is no high risk associated with TAPS operations as argued by the Carriers.¹⁴⁰ The record “runneth over” with evidence that the risks associated with TAPS encountered by the Carriers is simply not comparable to that of the Carriers’ parent companies’ line of business.

193. Anadarko/Tesoro’s witness Hanley confirmed that the risks associated with the original construction of TAPS have no bearing here some 35 years later. Ex. A/T-160 at 19-20, Tr. 2329-34; Ex. A/T-60 (revised at 4-5). Commission precedent instead looks forward to the current risks affecting current rates.¹⁴¹ Furthermore, the cost of capital is prospective, and here, the examination is focused on the years 2005 and 2006 forward. A/T-160 at 19. Therefore, the Carriers’ attempts to impute the risks

overseas. An insignificant amount of the Carriers’ parents earnings are from pipeline operations. *See* Tr. 1419.

¹³⁸ TAPS has no competition and is the only means of transporting Alaska North Slope (ANS) oil to market. Hanley, Ex. A/T-160 at 23, A/T-100. A/T at 26, A/T-132 at 8; Baumol, Tr. 3589. The Carriers, pursuant to the TSA, have recovered more than 80% of their investment and by 2006 have recovered more than 96% of their investment (including AFUDC). Ex. A/T-35 at 87; Ex. A/T-146, WP-4 at 4 (compare line 3 with line 7).

¹³⁹ Ex. A/T-132- at 9-10; Ex. A/T-100 at 26-27; Ex. A/T-132 at 51; *Trans Alaska Pipeline System*, 10 FERC ¶ 63,026, 65,203 (1980).

¹⁴⁰ Ex. A/T RB at 63; Tr. 2138, 2142; Tudor, Tr. 2135; Wells Tr. 2384; Tye, A/T-214 at 2-3.

¹⁴¹ *Transcon*, 60 FERC ¶ 61,246 at 61,827. Staff also notes that the rate of return is forward looking and while construction risks may be relevant for newly developed or developing projects, such risks are for the most part irrelevant for a project that was completed 30 years ago. Staff RB at 56. Staff further states that this is another important reason to match a forward looking ROE with a forward-looking capital structure. *Id.*

they faced during the construction and start-up phases of TAPS to the inquiry here are rejected as both irrelevant and disingenuous. Assuming *arguendo*, that it were proper to consider the risks of the original TAPS project, the record also shows that there was no risk that TAPS would not be completed.¹⁴²

194. The Carriers claim that because their parent companies are involved in diverse ventures, this diversification offsets their risks. Thus, the Carriers assert, the parent companies' diverse business is not riskier than the Carriers who have only one asset in one location. The Carriers cite *Container Corp. of America v. Franchise Tax Board*, 463 U.S. 159, 178-79 (1983), for the proposition that such diversification of risk serves to lower a company's risk. The testimony offered by Mr. Wells on risks of the Carriers and their parents is not persuasive in light of the evidence that at least a few of the TAPS Carriers' parents are dependent upon E&P for much of their earnings. Ex. A/T-205 at 5; Ex. A/T-206 at FS-2; Ex. A/T-209 at 39. Furthermore, Mr. Wells' testimony that the parent companies are "far less risky than the TAPS Carriers" is not convincing. Ex. ATC-203 at 12. The extensive record evidence supports the conclusion that the Carriers' parents risks are not comparable to that of the Carriers. Thus, it is found that the Carriers' parents' and the Carriers' business risks are clearly not comparable and that the parent's capital structure should not be used. Ex. A/T-53 at 8-10; Ex. A/T-100 at 6-10; Ex. A/T-160 at 6-8.

195. "The Commission reviews a pipeline's capital structure to assure that it is not contrived, or that the parent company's capital structure is not unrepresentative of the pipeline's risks." *SFPP, L.P.*, 96 FERC at 62,068. The Carriers capital structure (71.42% equity) falls outside the perimeters normally approved by the Commission.¹⁴³ While Anadarko/Tesoro claim that typical equity structures fall in the range of 45-55% equity, *see* A/T IB at 80, the Commission clearly views a capital structure with an equity percentage as high as 71% as being at the "at the extreme of what [the Commission has] approved in the past." *Colonial*, 116 FERC at P 62. The Commission's policy is to take those anomalous capital structures or those that are unrepresentative of a pipeline's risks and adjust them so that they are more

¹⁴² See A/T RB at 61-63; A/T-167 (Revised); Ex. SOA-72 at 2; Ex. SOA-73 at 6,891-20; *Trans Alaska Pipeline Sys.*, 10 FERC ¶ 63,026 at 65,198-204 (1980).

¹⁴³ See Tr. 1408-12, 1414-15 (Williamson states that the carriers' average 87 percent equity ratio is unprecedented); Ex. A/T-53 at 6-7, A/T-100 at 29 (Hanley stated the typical FERC approved capital structure in the range of 45 percent to 55 percent equity); *see also SFPP, L.P.*, 96 FERC at 62,065 (a capital structure of 45% to 55% debt is consistent with structures generally approved in the oil pipeline industry). Williamson, Tr. 1408-12, 1414-15; Ex. A/T-4 at 5, 12-13; Ex. A/T-53 at 5, 6-14; Ex. A/T-100 at 6-11; Ex. A/T-160 at 5-12, 37-39.

representative of the pipeline's risks.¹⁴⁴ In conclusion, it is found that the Carriers' parents' over-weighted equity structure is anomalous and falls outside the confines of debt to equity ratios previously approved by the Commission and will not be allowed here. In addition, it is found that the Carriers' proposed capital structures are inextricably high when compared to the DCF proxies forwarded by the parties.¹⁴⁵

196. As Staff points out, the Commission is against using an "unrepresentative parent company capital structure." Staff RB at 60; *SFPP, L.P.*, 96 FERC at 62,068. Staff also states that although the Commission has not yet adopted the use of a proxy group to determine hypothetical capital structures for an oil pipeline, it has adopted proxy capital structures for other regulated entities.¹⁴⁶ Since it has been found that the TAPS Carriers' parent companies' capital structure is "anomalous," a hypothetical capital structure will be employed.¹⁴⁷ This falls in line with Commission precedent using a hypothetical pipeline where the equity structure of the parent is "anomalous." *Id.* The Carriers' parents' equity structure is over-weighted with equity¹⁴⁸ and is not

¹⁴⁴ In *SFPP, L.P.*, 96 FERC 62,068 (the Commission rejected the use of the parent's capital structure with a 100% equity component in favor of a debt-to equity ratio 61%/29% more consistent with those used in the pipeline industry 45 to 55%); *Alabama-Tennessee*, 40 FERC at 61,814; *HIOS*, 110 P 143,147 *Entrega*, 113 FERC at P 32; *ARCO*, 52 FERC at 61,243; *Transcon*, 84 FERC ¶ 61,084; *SFPP, L.P.*, 96 FERC at 62,068.

¹⁴⁵ The Carriers' equity ratios of 85% and 87.5% as compared to the equity ratios of the proxy companies used in the DCF calculation of 45% for 2005 and 42% for 2006. Ex. A/T-5; Ex.A/T-53 at 5.

¹⁴⁶ *Id.* (citing *Alabama-Tennessee Natural Gas Co.*, 40 FERC at ¶61,244 at 61,814; *HIOS*, 110 FERC 61,043 at P 143,147).

¹⁴⁷ Staff RB at 53; A/T IB at 79; see *Entrega*, 113 FERC ¶ 61,327 at P 32; see *Transcontinental Gas Pipe Line Corp.* 90 FERC at 61,928 (The Commission's policy on determining whether to use the capital structure of the pipeline, as opposed to the parent or a hypothetical capital structure, is now well-defined.); *Michigan Gas Storage Company*, 87 FERC at 61,160; *Alabama-Tennessee Natural Gas Co.*, 40 FERC at ¶61,244 at 61,814 (1987) (*Alabama-Tennessee*); *HIOS*, 110 FERC 61,043 at P 147.

¹⁴⁸ Flint Hills argues that the parent companies' weighted average equity ratio for the period 1984-2004 of 71.46%, Ex. ATC-47, is close to the equity ratios for some natural gas pipelines. FHR IB at 34 (citing *Midwestern Gas Transmission Company*, 31 FERC ¶ 61,317; *Alabama-Tennessee Natural Gas Co.*, 13 FERC ¶ 61,224. The cases cited by Flint Hills to support their contention that a 71.46% equity ratio is close the equity ratios of some natural gas pipelines has been distinguished by the Commission in a subsequent decision. *Anadarko/Tesoro* and

comparable with the risks associated with the Carriers. Commission precedent mandates using a proxy group in such situations.

197. Anadarko/Tesoro's proxy-based capital structure sponsored by Mr. Hanley is appropriate. As a threshold matter, it is important to note that Mr. Hanley's testimony is credible and afforded considerable weight. Mr. Hanley's proxy is well supported in the record and the Carriers' attempts to discredit this capital structure are baseless.¹⁴⁹ The Commission will use a hypothetical capital structure based on the average equity ratio of a group of comparable MLP companies.¹⁵⁰ First, Mr. Hanley's proxy group is based on a representative group of oil proxy companies previously found acceptable by the FERC, and endorsed by the State.¹⁵¹ Specifically, Mr. Hanley used Buckeye Partners, L.P., Enbridge Energy Partners, L.P., KinderMorgan Energy Partners, L.P., and TEPPCO Partners, L.P. which are the same four pipeline companies that were used in *SFPP, L.P.*, 96 FERC at 61,099-100.¹⁵² In addition, Mr. Hanley further verified the reasonableness of his capital structure by using bond benchmarks. Ex. A/T-4 at 15; A/T-53 at 12-13. Mr. Williamson used this same proxy group for his test-period DCF analysis. Ex. ATC-45 at 16-17; Tr. 6860-61, 6864-65. Mr. Hanley also demonstrated that "the risk profile of the TAPS Carriers is comparable to both the four oil pipeline proxy group and the alternative gas pipeline proxy group, but significantly below that of the Carriers' parents, who exhibited nearly double the risk of the Carriers and the proxies."¹⁵³ A/T IB at 86.

Staff aptly note that a later Commission decision distinguished the two orders cited by Flint Hills and the underlying rationale was abandoned. A/T RB at 65 (citing *Alabama-Tennessee Natural Gas Co.*, 40 FERC ¶ 61,244 at 61,814).

¹⁴⁹ Hanley, Ex. A/T-4 at 5, 11-18; Ex. A/T 5 at 1; Ex. A/T-53 at 5-14; Ex. A/T-54 at 1; Ex. A/T-100 at 6-11; Ex. A/T-160 at 5-13, 37-39.

¹⁵⁰ Staff RB at 53; *Alabama-Tennessee*, 40 FERC at 61,815; *HIOS*, 110 FERC 61,043 at P 143,147.

¹⁵¹ A/T IB at 85; Ex. A/T-4 at 5, 11-18; Ex. A/T-5 at 1, Ex. A/T-53 at 5-14; Ex. A/T-54 at 1. Mr. Hanley's capital structure was endorsed by the State. Ex. SOA-44 at 53-62. Mr. Hanley's proxy group consists of four oil pipeline companies used by the FERC in *SFPP, L.P.*, 86 FERC ¶ 61,022 at 61,099-100 (1999).

¹⁵² Ex. A/T-4 at 13-14; Ex. A/T-6 at 6; Tr. 6821-22. These company names have been modified to reflect the impacts of name changes and acquisitions. Ex. A/T IB at 85.

¹⁵³ Thus, the record reflects that even as compared with different proxy groups, the parent's equity ratio is still significantly high.

198. The Carriers and Flint Hills take issue, and Staff notes a problem, with all of the members of the oil pipeline proxy group being MLPs. The concern stems from *HIOS*, 110 FERC ¶ 61,063, where the Commission excluded MLPs unless the MLPs' distributions had characteristics similar to a corporate dividend and *Sepulveda* in which the Commission found one company in the proxy group should be excluded for *HIOS* concerns. 117 FERC at P26. *Sepulveda*, *Kern River*, and *HIOS* present potential problems, as noted by Staff. *HIOS* excluded the use of MLPs unless distributions by the MLPs have the same characteristics as a corporate dividend. 113 FERC ¶ 61,280. As stated by the Commission, the "HIOS issue centers on a concern that the cost of equity capital may be skewed if distributions exceed earnings." *Sepulveda*, 117 FERC P 61,285 at P 26. More pointedly, the Commission explained that:

[T]he cash distributions of the MLPs it seeks to add to the proxy group in this case include a return of invested capital, in addition to a return on invested capital through an allocation of the partnership's net income..... the Commission uses the DCF analysis solely to determine the pipeline's return on equity. The Commission provides for the return of invested capital through a separate depreciation allowance. For this reason, to the extent an MLP's distributions include a significant return of investment, a DCF analysis based on those distributions, without any adjustment, will tend to overstate the estimated return on equity because the "dividend" would be inflated by cash flow representing return of equity, thereby overstating the earnings the dividend stream purports to reflect.

Kern River, 117 FERC at P 150.

199. In *Sepulveda* the Commission addressed a similar proxy group¹⁵⁴ used by Anadarko/Tesoro and the State and determined that one of the companies exhibited a HIOS issue. 117 FERC ¶ 61,285. The *Kern River* order also casts doubt on whether the oil pipeline proxy can be used to calculate equity return for capital structure purposes.¹⁵⁵ Staff properly notes that in *Sepulveda* and *Kern River*, the Commission did not preclude the use of MLPs if proper adjustments are made to account for the differences between MLPs and corporations.¹⁵⁶ In addition, in a Commission order

¹⁵⁴ Anadarko/Tesoro eliminated the company the Commission rejected in *Sepulveda*.

¹⁵⁵ 117 FERC ¶61,077; Staff IB at 26.

¹⁵⁶ Staff IB at 73; *Sepulveda*, 117 FERC at 30 (the Commission did not preclude the inclusion of Enron Liquids (the eliminated MLP) or its predecessor Kinder Morgan Energy Partners in the proxy group in any pending proceedings based on further analysis of the HIOS issue in those proceedings); *Kern River*, 117 FERC at

that was issued after the record in this proceeding was closed (March 27, 2007), the Commission stated that:

As we noted in *Kern River Gas Transmission Co.*, 117 FERC ¶ 61,077, at P 154 (2006), “[w]e do not intend in this order to foreclose non-MLP pipelines from proposing to include MLPs in the proxy group, with an appropriate adjustment to reflect the differences between MLPs and corporations.

Mojave Pipeline Company, 118 FERC 61,252 at P 14 n.4.¹⁵⁷ The four MLP proxy companies in this case have distributions per unit exceeding income per unit for a portion of the relevant time periods. Tr. 6815-6830:13; Ex. FHR IB at 37. Mr. Hanley addressed the MLP adjustment issue. First, Mr. Hanley stated that there is sufficient evidence in the record to make the adjustments; however, the effect of such adjustments would be minimal. Staff IB at 73; Hanley, Tr. 42/6826/66; Ex. FHR-56, 57, 58, 79. In addition, Mr. Hanley developed a separate proxy group of four diversified gas companies and confirmed that the gas proxy and the oil proxy are comparable from a financial and a business risk view point.

200. The oil proxy group (using the MLPs) yields a significantly lower equity ratio than that of the TAPS Carriers’ parents’ capital structures (71.42% parents vs. 45% MLP oil proxy). See A/T-4 at 4-5; A/T-5 at 1-2. It is relatively close to the capital structure of the gas proxy group (gas proxy 55% vs. 45% MLP oil proxy). See *id.* However, the overall effect as discussed further, *infra*, yields a significantly similar overall nominal cost of capital for 2005 (8.66% MLP oil proxy vs. 8.63% gas proxy). It would not be reasonable, in light of the discussion concerning the risk factors, to scrap Mr. Hanley’s MLP analysis in favor of using the Carriers’ parents’ capital structure that is clearly outside the range usually approved by the Commission.

P 147 (the Commission stated that it was “not making a generic finding that MLPs cannot, in future cases, be considered for inclusion in the proxy group if a proper evidentiary showing is made”).

¹⁵⁷ On April 11, 2007, Anadarko/Tesoro filed a motion to lodge the Commission’s order in *Mojave Pipeline Company*, 118 FERC ¶61,252 (2007) asserting that the order is relevant to the use of MLPs. Flint Hills filed an answer on April 26, 2007 stating that although it does not agree with Anadarko/Tesoro’s arguments, it does agree that the order is relevant and also requests that the order be lodged in this proceeding. Anadarko/Tesoro filed a reply on April 27, 2007. It is found that the *Mojave* order is relevant to the issues in this proceeding and is thus lodged to this record. Anadarko/Tesoro’s motion is hereby granted. Although Rule 213, 18 C.F.R. § 385.213 generally does not allow responses to answers good cause exists to allow Anadarko/Tesoro’s answer to further supplement the record.

Notwithstanding, the inclusion of MLPs, the equity structure produced by the oil proxy group are reasonable and credible when compared to the other proposed equity structures. Mr. Hanley acknowledged that there were differences in the capital structures of his oil and gas proxy groups (42% vs. 47% equity), but stated that the overall nominal after tax weighted return of both are similar for 2006 (8.60% vs. 8.05%). Ex. A/T-53 at 3-6; Tr. 42/6821, 6832. Moreover, the Commission's concern with MLPs is that "a DCF analysis based on those distributions, without any adjustment, will tend to overstate the estimated return on equity." *Kern River*, 117 FERC at P 150. As shown by Mr. Hanley, the MPL proxy yields an equity ratio lower than both the Carriers' parents capital structure and the gas proxy.

201. Staff also supports the proxy group and finds it particularly persuasive, as it is also found here, that the proxy group risk profile is comparable to Mr. Hanley's alternative gas pipeline proxy group.¹⁵⁸ In addition, Mr. Hanley's proxy group is comparable to capital structures adopted by the Commission for oil pipeline ratemaking purposes. Staff RB at 61. Thus, it is found that the oil pipeline proxy group supported by Mr. Hanley is credible and will be adopted to determine the appropriate capital structure for the Carriers. The capital structure adopted here is comprised of 55% debt and 45% equity for 2005 and 58% debt and 42% equity for 2006 based on the oil pipeline proxy companies.¹⁵⁹ The Carriers claim that each of the Carriers should be able to use its parent's capital structure in its return calculation.¹⁶⁰ The business risks for TAPS are virtually identical for each Carrier. Ex. A/T at 100. Thus, there should be only one rate of return which necessarily means there should be only one capital structure. *Id.* Thus, the Carriers proposal to use individual capital structures for each Carrier is rejected as Anadarko/Tesoro have shown that a single capital structure is more reasonable. Ex. A/T-100 at 11-13; Ex. A/T-160 at 5-6. Moreover, this is further corroborated by the Carriers' witness Williamson's calculation of a single capital structure. See Ex. A/T-100 at 11-13.

Issue III.F.2. What is the appropriate return on equity?

202. The Carriers state that the parties generally agree that the Commission's Discounted Cash Flow (DCF) methodology should be used to calculate the cost of equity (before the risk premium). Although the DCF models used by the Carriers,

¹⁵⁸ A/T-163; Staff IB at 73; RB at 60-61.

¹⁵⁹ The above findings are dispositive of Flint Hills' argument concerning proxy groups.

¹⁶⁰ The Carriers argue that the use of a proxy group capital structure is unprecedented for an oil pipeline, does not reflect the risks of TAPS, does not represent the capital structures of other Alaskan oil pipelines, and would serve as an impediment to the Carriers' ability to raise capital. Carriers IB at 83-86.

Anadarko/Tesoro and the State are substantially similar, there are still differences. The Carriers state that Anadarko/Tesoro and the State used an additional forecast from the Social Security Administration (SSA) which skews the forecast, resulting in a lower and, thus more favorable cost of equity for Anadarko/Tesoro. The Carriers also state that Anadarko/Tesoro failed to follow Commission precedent and failed to use the Global Insight Gross Domestic Product (GDP) forecasts for years prior to 2005 instead, relied on SSA and Energy Information Administration (EIA) forecasts. Finally, the Carriers state, the principal difference between the TAPS Carriers' position and the opposing parties' position involves the appropriateness of the risk premium.

203. Mr. Williamson applied the DCF methodology to the DCF proxy Group¹⁶¹ companies for the years in which it was possible to perform that analysis (1994-2004), the Carriers state. Next, for the period 1984 through 1993, for which the necessary data was not available, Professor Williamson used a Commission-approved Risk Premium approach. Last, the Carriers claim, to account for the fact that the risks faced by the TAPS Carriers exceed the risks faced by the proxy companies, Professor Williamson added a two percentage point risk premium to his cost of equity. The Carriers argue that this approach is reasonable. The Carriers state that Professor Williamson conducted a "backcasting" analysis utilizing the Risk Premium approach because the DCF proxy Group did not exist during 1984-1993. The Carriers claim that the Risk Premium approach has been accepted in Commission decisions.

204. Next, the Carriers claim that the Commission will add a risk premium to the midpoint of the DCF Proxy Group Range if the regulated pipeline is riskier than the pipelines in the proxy group. The Carriers state that TAPS is riskier than any Lower-48 oil pipeline and that warrants a risk premium of at least two percentage points. In concluding that a two percentage point risk premium is warranted, Professor Williamson relied on testimony from the original TAPS rate case which documented significant problems regarding TAPS construction. The Carriers argue that this percentage premium is consistent with the two percent risk premium approved by the Commission for Alaska Natural Gas Transportation System (ANGTS) where the Commission concluded that it was appropriate to compensate for the risk of non-completion. The Carriers state that since all of the proxy companies acquired pipelines already in existence and faced no risks associated with building a new pipeline, the two percentage point risk premium is particularly appropriate for TAPS. In addition, the Carriers state that over the period for which Professor Williamson

¹⁶¹ "A "proxy group" is a group of comparable companies used to determine a zone of reasonableness of rates of return, and to establish what the proper rate of return should be for the company under consideration." *Petal Gas Storage, L.L.C.*, 106 FERC ¶ 61,325 (2004) (*Petal Gas Storage*).

employed DCF analyses to determine a range of reasonable equity returns for the DCF Proxy Group, the average difference between the high end of the range of returns and the median return was 3.23 percentage points, which is well above the two percentage point risk premium that Professor Williamson recommends.

205. Anadarko/Tesoro claim that the record reflects that using the Commission's preferred DCF model, the appropriate ROE for TAPS for 2005 is 12.16% on a nominal basis (8.90% inflation adjusted), and for 2006 it is 12.31% on a nominal basis (8.89% inflation adjusted). First, Anadarko/Tesoro state that all the parties agree on application of the Commission approved DCF model. Each of the parties that presented evidence on the cost of equity, which includes Anadarko/Tesoro, the State and the Carriers, employed the DCF approach. However, Anadarko/Tesoro contend, because of internal input variations, minor, insignificant differences appear in the parties' calculated ROEs for 2005 and 2006. Anadarko/Tesoro state that Flint Hills who offered no evidence on this point, attempted to cast doubt on the use of MLPs as proxy companies where MLP distributions exceed earnings. Tr. 6814-34. Anadarko/Tesoro state that based on this record, where all the parties sponsoring cost-of-capital evidence agreed on the use of the four MLP oil pipeline proxies for purposes of their DCF analyses the Commission need not consider arguable distinctions between the composition of MLP distributions and corporate dividends. Additionally, Anadarko/Tesoro assert that impact of any such distinctions is minimal and, based on record evidence, could be accounted for through an earnings-capped adjustment to distributions used in the DCF calculation. In conclusion, Anadarko/Tesoro state that there is no material dispute regarding the use of the DCF method, the appropriate proxy companies, or the DCF-determined cost of equity.

206. Second, Anadarko/Tesoro claim that there is no support for a risk premium ROE adjustment. According to Anadarko/Tesoro, the Carriers propose to add a 200 basis point risk premium to the nominal ROE calculated under the DCF method based on the alleged risks facing TAPS. Anadarko/Tesoro claim that it and the State oppose any risk premium adjustment and that the proposal was discredited in its entirety by witnesses Hanley, Makhholm, and Ives. Anadarko/Tesoro claim that Commission precedent confirms that the Commission presumes all pipelines to be of average risk. Accordingly, Anadarko/Tesoro claim, the Commission will generally approve ROEs that fall in the median of the DCF range, absent highly unusual circumstances and a showing of anomalously high or low risk. In this case, Anadarko/Tesoro claim the record shows that TAPS has no greater operating risks and its risks from environmental and property damage are less than the proxy group.

207. The construction of the line is irrelevant or of historic interest only, Anadarko/Tesoro claim. In short, Anadarko/Tesoro conclude, since TAPS: (1) was built without any meaningful threat of competition, (2) anchored by vast proven reserves, (3) has shippers who are largely affiliates strongly motivated to ensure the

project's success, and (4) has investment costs that are essentially already recovered (and indeed over-recovered) through nearly 30 years of operation cannot credibly claim entitlement to any risk premium adjustment. Anadarko/Tesoro also argue that the Carriers backcasting is unnecessary because it is improper to recalculate the deferred returns and AFUDC balances in the Carriers' rate filings which already reflect the Carriers' balances from 1977. In addition, the Carriers' backcasting is flawed as shown by Mr. Hanley.

208. Staff states that the parties consistently applied the four proxy companies to the DCF analysis and that there is no material dispute among the parties as to the use of the DCF method or the nominal cost of equity. Staff does, however, note that there is a *de minimus* difference in the parties' DCF-based ROEs which Staff states is due to internal input variations and calculation errors. According to Staff, Anadarko/Tesoro witness Hanley has verified these variations and has shown that they do not result in significant differences in the nominal cost of equity. Staff also states that, as noted previously, the proxy consists of the four MLP oil pipeline proxies the Commission questioned in *Sepulveda* which casts some doubt on the use of MLPs. However, Staff asserts, the unique circumstances of this proceeding may still permit the Commission to accept the group. Alternatively, Staff suggests that the Commission should require the use of a gas pipeline proxy which was shown to represent risks comparable to TAPS and overall returns similar to the oil pipeline group. Staff states that the Commission previously relied on gas pipelines as a proxy for oil pipelines until sufficient evidence on oil pipelines became available. Since with the elimination of the oil proxy group such evidence would no longer be available, Staff asserts, it would be appropriate to go back to using gas pipelines as a proxy.

209. However, Staff states no matter which proxy group is used, the Carriers are not entitled to a special risk premium on their equity rate of return. The Carriers proposed risk premium must be rejected because (1) the rate of return is a forward-looking concept and the TAPS risks of construction are irrelevant and (2) the risks related to the construction and completion of TAPS were not that unusual. Staff claims that the Commission considers all pipelines to be of average risk and will generally adopt ROEs that reflect the median of the DCF range, absent highly unusual circumstances and a show of anomalously high or low risk. In instances where the Commission has deviated from the median to allow a ROE adjustment, it did so based on forward looking-risk factors unique to the regulated enterprise or shortcomings in the available proxy companies, Staff contends. Here, Staff asserts, there is no credible evidence that TAPS faces extraordinary, forward-looking, operational risks. Staff states that the arguments made by Carriers' witness Mr. Wells relate to the risk of construction and/or non-completion, and the risk that the investment will not be recovered. There is no persuasive rationale for burdening current ratepayers for these asserted risks, Staff states.

210. Staff states that the Carriers brief clarifies that their risk premium proposal is entirely related to the construction and completion risks of TAPS which are no longer present. The Carriers' proposal must be rejected because the Carriers have not met their burden to demonstrate that they require a return well outside the median of the DCF range. Staff concludes that the Carriers cannot credibly claim entitlement to any risk premium. Accordingly, Staff states, the appropriate return on equity using the consensus proxy group and applying the Commission's preferred discounted cash flow model is 12.16% on a nominal basis (8.90% inflation adjusted), and for 2006 it is 12.31% on a nominal basis (8.89% inflation adjusted).

Discussion/Findings

211. The DCF approach is based on the premise that a stock's price is a function of expected future cash flows, calculated using current dividend yields and estimated growth in dividends. A/T IB at 87; Tr. 6865. The DCF analysis is applied to the selected proxy group to produce a range of equity returns. A/T IB at 87; *see* Opinion 435, 86 FERC at 61,099. The median range is used by the Commission to set the return on equity for the regulated entity. *Id.* There is a noted exception to this practice. While the DCF analysis is applied in the same fashion to gas and oil pipelines, the calculation for gas pipelines, establishes a "nominal" return on equity, which includes a component for inflation and for oil pipelines a "real" ROE is calculated that subtracts the inflation factor from the "nominal" return on equity. *Id.*

212. The parties agree that the DCF Methodology is the appropriate methodology to employ in calculating the return on equity in this proceeding.¹⁶² In addition, the parties agree that the main point of contention is the 2% risk premium requested by the Carriers. Thus, the argument at hand is focused on whether the imposition of a risk premium is appropriate; however, the issues concerning the *de minimus* differences in the DCF model inputs must first be addressed. The parties agree that their application of the DCF proxy results in a difference that is immaterial.¹⁶³ However, the parties do note some difference.

213. First, the Carriers claim that the State and Anadarko/Tesoro used an additional SSA forecast which allegedly skews the DCF calculation and results in a lower cost of equity, to the benefit of Anadarko/Tesoro. Carriers' IB at 89. As stated by

¹⁶² A/T IB at 87; Carriers' IB at 89; Staff IB at 74-75, *see SFPP*, 86 FERC at 61,099. With regard to the use of MLPs in the proxy group, the Carriers, Staff and Anadarko/Tesoro agree that the use of such a proxy group is appropriate in this proceeding. Carriers' RB at 62 n.199; A/T RB at 69; Staff IB at 75.

¹⁶³ Staff IB at 75 n.237; Carriers' IB at 89; A/T IB at 87; Ex. A/T-100 at 15-17; Ex. A/T-104 (Column 11).

Anadarko/Tesoro and the State, the differences in the DCF-determined cost of equity is insignificant and attributable to input and calculation differences. A/T RB at 69 n.81; Staff IB at 75 n.237 A/T IB at 87; Ex. A/T-100 at 15-17; Ex. A/T-104 (Column 11). Contrary to the Carriers' assertions, Anadarko/Tesoro's use of the EIA and SSA for the long term growth rates is consistent with Commission precedent.¹⁶⁴ The Commission rejected the same argument forwarded by the Carriers' and their witness Mr. Williamson. The argument was that two of the forecasts should be rejected because the forecasts were lower than the others and were thus, as Williston Basin claimed, unreliable. *Williston Basin*, 104 FERC at P31; Carriers' IB at 89; ATC-45 at 23; *See State IB at 57*. The Carriers' witness Mr. Williamson admitted that in *Williston Basin* the "Commission accepted the inclusion of GDP growth forecasts from SSA" for the DCF calculation 104 FERC at P32; ATC-45 at 45:5-6.

214. Mr. Williamson's reason for excluding the SSA GDP forecasts, *inter alia*, was because they "reflect extreme conservatism" and as stated by the Carriers, "skews the forecast, resulting in a lower and, for Anadarko/Tesoro, a more favorable cost of equity." Carriers' IB at 89; Ex. ATC-45 at 23; *see Ex. A/T-100 at 24:18-21*. Mr. Hanley used the information from the SSA and EIA because it was "freely available and cost-free" whereas getting the DRI/WEFA estimates is "time-consuming and extremely costly." Ex. A/T-100 at 24. A reasonable inference can be drawn here that Mr. Williamson's main purpose for excluding the SSA GDP forecasts in his DCF analysis is because they would yield a lower cost of equity (which is unfavorable to the Carriers). Carriers' IB at 89; ATC-45 at 23, *see State IB at 57; see Staff IB at 62; see Ex. AT-100 at 24*. In addition, Mr. Williamson's choice to exclude the SSA forecast after admitting that the Commission accepts the SSA forecast in DCF calculations is suspect particularly when the point of the exercise is to determine a range (both high and low) and not just an exact number. Thus, Mr. Williamson's testimony with respect to this issue will be accorded little weight. Mr. Hanley's use of an additional GDP SSA forecast, approved for use in the DCF analysis by the Commission, in his calculation renders his study more reliable than Mr. Williamson's.

215. As an additional ground for rejecting Mr. Williamson's DCF analysis Mr. Hanley notes that Mr. Williamson's calculations contain timing mismatches. To begin with, Mr. Hanley points out that the cost of common equity is prospective, and thus applicable to a future period. A/T-100 at 16. Mr. Hanley states that the calculation should take into account the time period in which investors would examine the data to form their expectations and that is usually the end of the proceeding year (when they form expectations for the following year). Mr. Hanley states that since investor's expectations are formed in the previous year, there is a

¹⁶⁴ State IB at 57; *Williston Basin*, 105 FERC ¶ 61,036 at 21-33; Ex. ATC-45 at 23.

mismatch between the data used and the expectational cost of common equity capital. *Id.* at 18-19. Mr. Hanley further states that the actual result is not what should be considered, but instead what the investors expected. Thus, the expectational cost for one year is measured by the actual data from the previous year. Mr. Williamson's calculations do not reflect this practice and, accordingly, result in a mismatch between the data used and the expectational cost of common equity capital. *Id.* at 17.

216. Accordingly, the Carriers' DCF analysis is rejected in favor of adopting Anadarko/Tesoro's analysis.¹⁶⁵ As explained previously the differences in the DCF calculations of the Carriers and Anadarko/Tesoro are insignificant. It is found that the appropriate return on equity (ROE) calculated using the DCF methodology inputs of Anadarko/Tesoro for TAPS for 2005 is 12.16% on a nominal basis (8.90% inflation adjusted or real equity return), and for 2006 is 12.31% on a nominal basis (8.89% inflation adjusted or real equity return). Hanley, Ex. A/T-5 at 5, 11-18, A/T-53 at 5, 6-14, A/T-100 at 10, 25-30, A/T-160 at 5-13, 37-39.

217. Now, considering the more significant point, the Carriers claim that a risk premium of 2% or 200 base points should be added to their return on equity because TAPS is "riskier than any Lower-48 oil pipeline." Carriers IB at 90. In *Petal Gas Storage*, the Commission stated that

[I]t begins the risk analysis for proposed projects with the assumption that pipelines generally fall into a broad range of average risk. Absent highly unusual circumstances that indicate an exceptionally high or low risk as compared to other pipelines, the assumption is made that a pipeline faces average risks (though an examination of a particular pipeline's risk factors may warrant adjusting the ROE higher or lower than the middle of the zone of reasonableness established by the proxy group).

106 FERC at P 8 (citations omitted). The Commission further stated that "we conduct our risk analysis with the presumption that existing pipelines fall into a broad range of average risk, absent highly unusual circumstances that indicate anomalously high or low risk as compared to other pipelines." *Id.* at P 29; Staff IB at 76; A/T IB at 88. Additionally, the Commission requires a "sufficient showing that [the pipeline] is outside the broad range of average risk." *Id.*; see *Kern River*; 117 FERC at P 160-161. Thus, the inquiry here begins with the presumption that the Carriers as an existing pipeline "fall into a broad range of average risk" and await "a sufficient showing" that the Carriers fall outside this broad range. See *id.*

¹⁶⁵ The HIOS issues in the oil proxy group are discussed under Issue F.1, *supra*.

218. As discussed in Issue III.F.1, *supra* the Carriers have failed to prove that operating TAPS is riskier than the operations of other oil pipelines.¹⁶⁶ In addition, Mr. Hanley notes that TAPS' business risk is average and TAPS's financial risk is average. A/T-4 at 22. The Carriers state that *Colonial* confirms that a rate of return toward the top of the range of reasonableness is justified based on the facts of this case. Carriers' RB at 70-71. *Colonial* was distinguished from TAPS in Issue III.F.1. The Commission's decision to grant *Colonial* a provisional acceptance of its equity ratio at the high end of the "zone of reasonableness" was based on the Commission's recognition that *Colonial*'s construction project was going to present "substantial challenges" such as the length and scope of the project, enormous investment involved, financing challenges, the challenges of constructing a multi-state project, and the short time for completion of the project. *Colonial*, 116 FERC at P 59, 61-62, 65. TAPS is a completed pipeline and does not face such challenges at this time.

219. The Carriers assert that the risks TAPS faced during construction merits a 2% risk premium since the challenges and risks that TAPS faced in the past are relevant in the present. However, the case law indicates that the risk premium inquiry is forward-looking. In *Iroquois Gas Transmission Sys., L.P.*, 84 FERC ¶ 61,086 at 61,455-56 (1998) (*Iroquois*), the Commission upheld the ALJ's decision not to move the pipeline's ROE outside the range established by the proxy companies after finding that the pipeline's risk was average and that an "established pipeline serving an expanding market, that it has the security of long-term shipper contracts, and that any risks associated with construction or certification are either past or speculative." The forward-looking nature of the Commission's risk determinations was also confirmed in *Transcon. Gas Pipeline*, 60 FERC at 61,287, where the Commission stated that the inquiry is

[B]ased on the Commission's evaluation of [the pipeline's risks] which investors perceive while the rates in this proceeding are effective. The Commission establishes rates to apply in the future that reflect projections of what costs, and risks, the pipeline is likely to incur during the period the rates will be in effect. These projections are based on historical experience, adjusted for known and measureable changes that will occur to affect costs or risks during the period the rates will be in effect.

¹⁶⁶ See A/T IB at 88-90; Staff IB at 76. TAPS has an impressive safety and reliability record. Tr. 2138, 2142; Tudor, Tr. 2135; Wells Tr. 2384; Tye, A/T-214 at 2-3. TAPS has no greater than average operating risk. Tr. 2135. TAPS has not had a reportable spill of crude in 4 ½ years. Tr. 2142.

Transcon. Gas Pipeline, 60 FERC at 61,287. Thus, the testimony of witness Wells and the Carriers' other arguments concerning construction risk are irrelevant. Wells, ATC-151 at 6-7. Tr. 2329.

220. The fact still remains that the record does not support a finding that TAPS was a risky enterprise in either its construction phase or its operational phase, and more importantly prospectively.¹⁶⁷ The Commission requires the risks to be sufficiently high to justify a further increase in return. *See Kern River*, 117 FERC at P 177. The Carriers have not satisfied this requirement. Thus, Professor Williamson's extensive discussions concerning risk premiums is rejected. The Carriers' have not cited a case where the return on equity and associated risk premium issue was not a prospective inquiry. It is found that the Carriers failed to rebut the presumption that they face average risks and it is found that the Carriers are not entitled to a 2% risk premium.

Issue III. F. 3. What is the appropriate cost of debt?

221. The Carriers claim that the appropriate cost of debt is that of the Carriers' parent companies. The Commission's policy is that capital structure and long term debt cost should be based on the same entity, the Carriers claim. According to the Carriers, the Commission's policy in Opinion 154-B is to use the pipeline's parent company's capital structure and cost of long-term debt where the pipeline company does not provide its own financing. The Carriers state that the reasons they provided for using the parent company capital structure also support the use of the parent company's cost of long-debt. The Carriers claim that they and the State generally followed the same approach in determining the cost of debt using the parent companies. The actual long-term debt costs of the Carriers' parent companies are not uniform, and accordingly, Anadarko/Tesoro's proposal to use a uniform hypothetical debt cost for all TAPS Carriers would violate the requirement that each of the Carriers parents be compensated for the debt costs it has actually incurred, the Carriers contend.

¹⁶⁷ As Staff and Anadarko/Tesoro succinctly state "here there is no credible evidence that TAPS faces extraordinary, forward looking, operational risks. Indeed, the record supports the conclusion that TAPS: (1) was created without a threat of future competition, (2) has recognized oil reserves, (3) is contractually subscribed by affiliated shippers with interests to continue to ensure the success of TAPS, (4) whose original investment has already been substantially recovered, and, accordingly, (5) cannot credibly claim entitlement to any risk premium." Staff IB at 76 (citing Hanley, A/T-4 at 5, 11-18, A/T-53 at 5, 6-14, A/T-100 at 10, 25-30, A/T-160 at 5-12, 37-39). A/T-IB at 91. Ives, SOA-8 at 80; Makhholm, SOA-44).

222. Anadarko/Tesoro state that the appropriate cost of debt for TAPS for 2005 is 5.80% and for 2006 is 5.91% as determined by the oil proxy group. The Carriers' use of the parent company debt costs is inappropriate because the parents have materially different risk profiles and capital structures than TAPS. Anadarko/Tesoro claim that where the use of parent company capital structures is inappropriate and unreasonable, it follows that using the Carriers' parents' cost of debt to TAPS is also unreasonable. Anadarko/Tesoro state that Mr. Hanley's cost of debt calculations should be accepted because although the variations in recommended debt rates are minimal, only Mr. Hanley's proposal reflects the consistent use of proxy companies to determine all cost of capital elements. Mr. Hanley's proposal is consistent with Commission precedent that requires the use of a proxy group to develop a hypothetical capital structure where the use of the parent's capital structure would produce anomalous results.

223. Staff agrees with the cost of debt proposed by Anadarko/Tesoro. Staff states that although the State calculated the cost of debt using the weighted average embedded cost of debt of the Carriers' parents, the variations are insignificant. However, Staff asserts that the record does not support the use of parent company debt costs because the Carriers' parents have materially different risk profiles and capital structures than TAPS. Staff states that as with the determination of the TAPS equity return, it is also appropriate here to utilize a proxy group of risk-comparable pipeline companies to determine the cost of debt for TAPS. Moreover, Staff claims that as a matter of policy, the debt cost should be in synch with the capital structure. It follows that where the use of parent company capital structures is inappropriate and unreasonable, ascribing the parents' cost of debt to TAPS is likewise unreasonable. Staff states that the Carriers' arguments must be rejected because it is inappropriate to apply the Carriers' parents' capital structures to TAPS and, thus, using the parents' cost of debt for TAPS is precluded.

Discussion/Findings

224. The parties agree that Commission precedent mandates that the cost of debt be consistent with the capital structure. As discussed above, it was found that the Carriers' parents' capital structures are anomalous and cannot be used. The hypothetical capital structure was adopted and, thus for the sake of consistency, the cost of debt will be of the same design as the capital structure implemented in this decision. Staff, Anadarko/Tesoro, and the Carriers all cite *Enbridge Pipelines*, 100 FERC ¶61,260 at 61,944 (2002) and *Michigan Gas Storage Co.*, 87 FERC ¶ 61,038 at 61,166 (1999) for the proposition that the capital structure imputed to a pipeline should also be imputed to the cost of debt.¹⁶⁸ Thus, they all agree (whether or not

¹⁶⁸ *Enbridge*, 100 FERC at 61,944 ("when the Commission imputes the capital structure of a corporate parent to a subsidiary, it also imputes the parent's costs of debt and preferred stock to the subsidiary"); *Michigan Gas Storage Co.*, 87 FERC ¶ 61,038

they agree with the final outcome of the capital structure findings) that this is the appropriate result. Staff IB at 78; RB at 64; Carriers' RB at 69; IB at 92; A/T IB at 91; RB at 72. Accordingly, it is found that the cost of debt will be calculated in accordance with the findings concerning capital structure.

225. As a result of all the findings above on Issue III. F. or the appropriate return on investment, it is concluded that the weighted cost of capital in this case is 7.20 percent in 2005¹⁶⁹ and 7.16 percent in 2006.

Issue III. G. What is the appropriate income tax allowance?

226. The parties agree that this issue is derivative of other issues. Accordingly, this issue is not in dispute. *See* A/T IB at 92; Carriers' IB at 94; Staff IB at 78.

Issue III. H. What level of throughput is appropriate to use in developing rates?

227. The parties have agreed to accept the Carriers' estimated throughputs for 2005 and 2006, accordingly, this issue is not in dispute. *See* A/T IB at 92; Carriers' IB at 94; Staff IB at 78. The Carriers' throughput figures are found in Exhibits 37-41, Statement A2 and Workpaper 1 for 2005 and Exhibits 90-94, Statement A2 and Workpaper 1 for 2006.¹⁷⁰

Issue III. I. What cost allocation and rate design is appropriate?

228. This issue is not in dispute. *See* A/T IB at 92; Carriers' IB at 94; Staff IB at 78.

at 61,166 (1999) ("when the Commission imputes the capital structure of a corporate parent to a subsidiary, it also will impute the parent's costs of debt and preferred stock").

¹⁶⁹ Exs. A/T-13, WP1; A/T-144, WP1.

¹⁷⁰ Ex. A/T-146, WP1.

Issue III. J. Does the Designated TAPS Carriers' SAC presentation show that the filed 2005 and 2006 interstate rates are just and reasonable?

Parties' Contentions

229. The Designated TAPS Carriers (the Designated Carriers)¹⁷¹ propose the stand alone cost (SAC) methodology as an additional benchmark to show that their filed rates are just and reasonable. The Designated Carriers claim that if their filed rates are lower than the rates determined under SAC, that will serve as an additional indicator that the Carriers' filed rates are just and reasonable. Precedent from the D.C. Circuit, the Supreme Court, other commissions, and this Commission support the use of SAC to evaluate the reasonableness of TAPS rates, the Designate Carriers claim. The Designated Carriers state that the average rate derived by Mr. Klick for all New Alaska Pipeline System (NAPS) is \$5.34 per barrel in 2005 and \$5.52 per barrel in 2006. Since these rates are higher than the Carriers' filed rates for 2005, the Designated Carriers claim that this proves the filed rates are just and reasonable.

230. In addition, the Designated Carriers assert that SAC acts as a surrogate for competition by replicating the competitive market in situations where competition is absent and enables regulators to determine the maximum rate a carrier could charge if competition existed. In sum, the Carriers state that SAC shows the rates that could be charged if TAPS was subject to effective competition. Thus, the Designated Carriers contend, the SAC analysis determines the maximum rate that an economically efficient new entrant could charge for the same service. If the SAC rate is higher than the filed rate, the Designated Carriers assert, then the filed rate is deemed just and reasonable.

231. The Designated Carriers state that they are not using SAC to establish the Carriers' rates. The Designated Carriers claim that it is irrelevant that SAC is not an original cost methodology because the Commission is not required to adhere exclusively to original cost ratemaking. Revenue adequacy principles are not important, the Designated Carriers argue, since they are not arguing that the SAC rates should be submitted for their filed rates.

232. Anadarko/Tesoro state that the SAC does not support the justness and reasonableness of the Designated Carrier's filed rates. SAC is a form of a replacement cost method grounded in hypothetical costs of operating a hypothetical

¹⁷¹ The Designated TAPS Carriers are: BP Pipeline (Alaska); Exxon Mobile Pipeline Company; Koch Alaska Pipeline Company, LLC and Unocal Pipeline Company.

pipeline and contradicts the original cost method required by *Farmers Union II* and Opinion 154-B. First, Anadarko/Tesoro state that the SAC is fundamentally inconsistent with original cost ratemaking because it fails to take any actual costs of TAPS into consideration. Anadarko/Tesoro state that the SAC is a replacement cost valuation methodology that has been repeatedly rejected by the courts and the Commission. According to Anadarko/Tesoro, SAC is an allocation methodology used to allocate a total revenue requirement among competitive and noncompetitive services. The Designated Carriers incorrectly use SAC to justify their revenue requirement Anadarko/Tesoro claim. Anadarko/Tesoro also claim that the Designated Carriers SAC presentation is unreliable because even the hypothetical pipeline is substantially different from TAPS. The SAC is incapable of distinguishing among rates lower than the SAC ceiling rate, Anadarko/Tesoro contend. Anadarko/Tesoro state that the case law cited by the Designated Carriers misstates relevant precedent and that the SAC analysis has not been used or recognized by the Commission.

233. Staff agrees with Anadarko/Tesoro and also states that the Designated Carriers' SAC proxy is deficient and does not support a finding that the filed rates are just and reasonable. Staff presents many of the same arguments as Anadarko/Tesoro concerning SAC including that it ignores front loaded accumulated depreciation and all other actual costs. First, Staff states that the SAC is inconsistent with original cost ratemaking as adopted in *Farmers Union II* and Opinion 154-B and should be rejected. Staff claims that SAC does not make an assessment as to the justness and reasonableness of the individual TSM elements and only evaluates the overall rate and thus fails to satisfy the requirement that all non-cost elements of the TSM be justified. The Designated Carriers have not supported the SAC they advance and the SAC does not support the Carriers' filed rates, Staff claims. Second, Staff asserts that SAC is premised on replacement cost principles rejected by the Commission and the courts. Third, Staff states that the SAC is inappropriately used by the Designated Carriers to establish a purported new revenue requirement. The Commission has specifically rejected the use of SAC to set an overall revenue requirement, Staff states. SAC, Staff contends, may have some value as an allocation method however, the Designated Carriers are using SAC to assess the reasonableness of their rates and not simply to provide a benchmark. Finally, Staff states that the Designated Carriers' arguments stating that SAC should be applied to alleviate concerns about generational equity should carry no weight.

Discussion/Findings

234. As Staff correctly points out, the SAC methodology was primarily used by the Interstate Commerce Commission and its successor agency the Surface Transportation Board to allocate costs between captive and non-captive customers of coal-hauling railroads. *See* Staff IB at 86 n. 271. This methodology attempts to

determine the rate that a shipper would pay if the market were competitive by calculating the costs of a hypothetical pipeline. Carriers' IB at 94; A/T IB at 94.

235. As a threshold matter, it is noted that this initial decision has already found above that *Farmers Union II* and Opinion 154-B are the applicable ratemaking standards in this proceeding. Thus, this issue can easily be disposed of using the basics set forth in these two precedents. As discussed, *supra*, in Issue II.B, *Farmers Union II* provided the Commission with several "guideposts" to use in setting just and reasonable rates. See *Farmers Union II*, 734 F.2d at 1530. Under the original cost methodology articulated in Opinion 154-B, the Commission stated that "original cost is a 'proven alternative'" and "is the best yardstick" to use in determining revenue requirements. 31 FERC at 61,833. In addition, Opinion 154-B stated that "oil pipeline rates as a general rule must be cost-based." *Id.* SAC runs afoul of the cost-based principles established in Opinion 154-B.

236. The SAC is based only on forward-looking costs and does not take the original cost of the rate base into consideration.¹⁷² This methodology fails to take any cost into consideration including actual accumulated depreciation and the original cost of rate base and starts from scratch to create a "different rate base, different expenses, different everything." Overcast, Tr. 6272-6273. As noted by Anadarko/Tesoro, the SAC ignores the accelerated depreciation already collected by the Carriers that has resulted in a 97% recovery of their original cost investment in TAPS. A/T IB at 95-96; Ex. A/T-33; Ex. A/T-35. Moreover, implementing costs derived under SAC would permit the Carriers to cover costs completely unrelated to their original investment in TAPS. A/T IB at 95; Ex. A/T-79 at 31-32. Contrary to the Carriers' assertions, Dr. Overcast states that "SAC cannot be used to test the revenue requirement because it does not reflect any of the elements of the total revenue requirement calculation as is required under the regulatory model."¹⁷³ Even the Carriers' witness Dr. Baumol agrees that SAC "has nothing to with the revenue requirements" and [a]s one of the inventors of the concept, I can guarantee you that that is not its purpose." A/T IB at 100 (quoting Tr. 3588). Thus, the Carriers' witnesses also agree that SAC cannot be used to determine just and reasonable rates. A/T IB at 101. Anadarko/Tesoro also point out that no witness knew of a case where an agency used SAC to determine the total revenue requirement.¹⁷⁴ Dr. Baumol, the methodology's originator, admitted

¹⁷² Overcast, Tr. 6272-2673; Ex. A/T-93 at 17, 24-26, 28; Ex. A/T-78 at 60-62, 65-66; Ex. A/T-140 at 14-15; A/T at 28,29-34; DTC-1 at 16; DTC-2 at 10; DTC-5 at 11-12; DTC-36 at 14.

¹⁷³ A/T-93 at 24. In addition, Dr. Baumol stated that the SAC computes a competitive ceiling; however, it does not determine what the competitive rate should be. Tr. 3612.

¹⁷⁴ See A/T IB at 100 (citing Klick, Tr. 3444, Tr. 3467; Overcast, Ex. A/T-93 at