

SB

192

(FILE 2)

<TARGET><BILL>SB 192</BILL><SUBJECT>SB 192 (FILE
2)</SUBJECT><COMM>SFIN27</COMM></TARGET>

Table of Contents

15. Robin Brena and Craig Richards presentation to Senate Resources Comm.
16. Gleason Decision
17. Oil Industry Profitability in Alaska 1969 through 1987
18. BP Doc re: Cash Cow
19. Therriault Email
20. Revenue Source Book re ANS Production Decline handout
21. "With Prudhoe Bay in Decline, What's Next for Alaska?" (August 3, 1992)
22. Testimony to the US Senate by Kevin Banks, Director, Div of Oil and Gas (May 10, 2011)
23. Alaska Economic Trends: Alaska's Oil Industry (September, 2008)

15.

**Robin Brenna &
Craig Richards
Presentation to
Senate Resources
Committee**

Senate Resource Committee Presentation

By Robin O. Brena and Craig W. Richards



February 6 – February 8, 2012

Introduction

Decision Following Trial De Novo, Case No. 3AN-06-8446 CI
(2007-2009 Tax Years Consolidated) Assessed Valuations of the Trans Alaska
Pipeline System (December 30, 2011)
("Gleason Decision")

Robin O. Brena—Counsel for the Fairbanks North Star Borough and Lead Counsel
for the Municipalities in the 2007-09 Assessed Valuations Case for TAPS

Craig W. Richards—Counsel for the City of Valdez and Co-Counsel for the
Municipalities in the 2007-09 Assessed Valuations Case for TAPS

Mr. Brena and Mr. Richards are testifying as to their own personal opinions as
Alaskan residents and are not representing any client or being paid for their
testimony.

Introduction

Robin O. Brena

Mr. Brena is a life-long Alaskan who grew up in Skagway. He has received a Masters of Business Administration (“MBA”) and a Doctor of Jurisprudence (“JD”) from the Willamette University and a Master of Laws in Real Property (“LL.M.”) from the University of Miami. He has been the Chairman of the Real Estate Section of the Alaska Bar Association, Chairman of the Estate Planning and Probate Section of the Alaska Bar Association, and has taught Advanced Business Law at the University of Alaska.

Mr. Brena is the owner of Brena, Bell & Clarkson, P.C., an Anchorage law firm that emphasizes oil and gas, public utilities, tax assessment, real estate, commercial, regulatory, and telecommunications law. Representative current and prior clients in the oil and gas and tax assessment areas of practice are Fairbanks North Star Borough; Anadarko Petroleum Corp.; City of Valdez; Tesoro Corporation; Aurora Gas, LLC; Aurora Power Resources, Inc.; Murphy Exploration (Alaska) Inc.; Cook Inlet Energy, LLC; Agrium Inc.; Nabors Alaska Drilling, Inc.; Doyon Drilling, Inc.; Doyon Parker Joint Venture; Nordic-Calista Services No. 1; and Parker Drilling, Inc.

Mr. Brena has been involved in several major tax assessment cases in Alaska involving drilling rigs, an oil refinery, tankers, and pipelines. He has also been involved in the many of the major pipeline regulatory cases before the Federal Energy Regulatory Commission (“FERC”), the Regulatory Commission of Alaska (“RCA”), and the Washington Utilities and Transportation Commission (“WUTC”) involving the Trans-Alaska Pipeline System (“TAPS”), Cook Inlet Pipeline System (“CIPL”), Cook Inlet Gas Gathering System (“CIGGS”), Kenai Pipeline Company (“KPL”), Olympic Pipeline, and Enstar.

Mr. Brena represented the Fairbanks North Star Borough and was the lead counsel for the Municipalities before the Honorable Judge Gleason in the ad valorem case concerning TAPS for the 2007-09 tax years.

Introduction

Craig W. Richards

Mr. Richards grew up in Fairbanks, Alaska, where he graduated from West Valley High School in 1993. He studied finance as an undergraduate at the University of Virginia, and holds a *Juris Doctor* from Washington & Lee University and a MBA from Duke University.

Mr. Richards practices law with Bill Walker and Joe Levesque at Walker & Levesque, LLC in Anchorage, Alaska. His practice focuses on finance, tax, municipal, and oil and gas law. Mr. Richards has been involved with numerous oil and gas taxation disputes, including those relating to TAPS and the tankers that call at Valdez. Through his representation of the Alaska Gasline Port Authority, as well as other clients, he has spent many years working on an LNG project to Valdez. He has also been actively involved in the proposal to truck North Slope gas to interior Alaska, and the proceedings related to the termination of the Point Thomson Unit. The firm also acts as bond counsel on TAPS' refinancings.

Mr. Richards, along with Mr. Walker, represented the City of Valdez before the Honorable Sharon Gleason in the recent de novo trial relating to the 2007 – 2009 assessed value of TAPS.

Introduction

1. This is a consolidated appeal of the State Assessment Review Board (“SARB” or “Board”) Decisions of the 2007, 2008, and 2009 assessments of the Trans Alaska Pipeline System (“TAPS”) for ad valorem tax purposes under AS 43.56. SARB assessed the value of TAPS for 2007 at \$4.588895312 billion, for 2008 at \$6.154447972 billion, and for 2009 at \$9.045892 billion.

Gleason Decision ¶ 1

Introduction

599. [F]or the reasons expressed herein, this Court finds that as of January 1, 2007, 2008, and 2009, the “full and true value” of the Trans Alaska Pipeline System, “with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically, and legally deliverable into the transportation facility” is \$8.941 billion for 2007, \$9.644 billion for 2008, and \$9.249 billion for 2009.

Gleason Decision ¶ 599

Introduction

Source Materials

2007-2009 Decision:

http://akdemocrats.org/rep_gara/2012/01/05/sen-french-bp-withholds-oil-pipeline-evidence-credibility-in-oil-tax-debate-questioned/

2006 Amended Decision:

<http://aws.state.ak.us/officeofadminhearings/Documents/TAX/TAX06SARB%20Amended%20Sup%20Ct%20decision.pdf>

Overview

- Introduction
- Overview
- Market Structure
 - Integrated Operations with Concentrated Market Power
 - Stages of Development
 - Barriers to Competitive Entry
- The Life of TAPS
 - Price of ANS Crude Oil
 - Reserves and Throughput
 - Minimum Mechanical Throughput
- Access to Information
- Conclusion

Overview

546. Brent Eyre, on behalf of the Municipalities, employed a discounted cash flow income approach to value the integrated economic unit of which TAPS is a part at \$40.2 billion in 2007, \$44.2 billion in 2008, and \$50.4 billion in 2009. Dr. James Smith, on behalf of the Owners, testified that Mr. Eyre's unit value of the integrated ANS enterprise should be reduced by slightly less than 10% for each year, for a value of \$36.4 billion in 2007, \$41.1 billion in 2008, and \$46.0 billion in 2009.

Gleason Decision ¶ 546

Overview

Integrated Value of the ANS Unit

Comparison of Valuation Results, Before and After Corrections (all values in \$ billions)			
	Jan 1, 2007	Jan 1, 2008	Jan 1, 2009
Results Reported by Mr. Eyre			
Eyre	System	\$40.159	\$44.208
	TAPS	\$8.812	\$10.688
Results Obtained from Corrected Model			
Smith	System	\$36.401	\$41.079
	TAPS	\$0.259	\$2.555

TO-07-433 (Dr. Smith Chart)

Market Structure

Integrated Operations with Market Power

Concentrated Market Power Integrated Value of the Unit

- Shows ANS unit will generate roughly \$36 - \$50 billion in discounted cash flow value
- **Current Value of Parts of the Unit Substantially Less than \$36 - \$50 billion**
 - Taxable upstream assets, most valued on RCNLD, assessed at between \$8-\$10 billion for 2007 to 2009 [2007-2009 Trial Tr. 13040 (Greeley)]
 - Even under Dr. Smith's calculations, a \$13 billion TAPS value leaves between \$13 billion and \$26 billion in unallocated unit value for non-taxable property
 - Includes intangibles (if any), leases, certain locally assessed property, etc. [See AS 43.56.020; AS 43.56210(5)(B)]
- **Unit Income is Sufficient to Justify:**
 - Billions in capital investment above the over \$2 billion annual capital investment already anticipated in the integrated model
 - Replacing TAPS at \$20+ billion
 - A \$13+ billion TAPS value

Market Structure Overview

- Integrated Operations with Market Power
- Stages of Development
- Barriers to Competitive Entry

Market Structure

Integrated Operations with Market Power

- Integrated Operations
- Market (ANS Basin) Dominance by Big 3
- Limited Competition

Market Structure

Integrated Operations with Market Power

69. The TAPS Owners did not and could not have independently financed the original construction of TAPS and they do not independently finance substantial improvements to TAPS. Instead, the affiliated production companies have financed TAPS' construction. And the evidence at trial demonstrated that all significant funding decisions for TAPS are not made by the TAPS Owners, but by the affiliated parent corporations or upstream producer affiliates of each Owner.

Gleason Decision ¶ 69

Market Structure

Integrated Operations with Market Power

70. As of the lien dates, the parent companies of the three largest owners of TAPS (BP, ConocoPhillips, and ExxonMobil) had a combined 95% ownership interest in TAPS. These same three parent companies also had a combined total in excess of 96% of the estimated production on the North Slope. This close correlation between estimated production and ownership interest in TAPS is expected to remain in place for the foreseeable future. . . . [E]ach of the five TAPS Owners has an affiliate with oil to be transported on TAPS.

Gleason Decision ¶ 70

Market Structure

Integrated Operations with Market Power

71. Each Owner's affiliated producer has an economic incentive to nominate its ANS production to its affiliated TAPS Owner. As explained by Charles Coulson, the President of BP Pipelines:

There has been a strong pattern of shippers on TAPS nominating their barrels to affiliated pipeline companies. There are a variety of reasons for this behavior, but mostly it can be understood by thinking about integrated corporate economics. When an upstream affiliate ships barrels in its pipeline affiliate's space, it pays the published tariff rate to the pipeline affiliate, and no money leaves the corporate family.

Gleason Decision ¶ 71

Market Structure

Integrated Operations with Market Power

114. In the case of TAPS, AS 43.56.060(e)(2)'s reference to "economic value" and not "market value" is consistent with the reality that there is no market for TAPS as a standalone investment based solely on its tariff income. Even if there might be a buyer of TAPS based solely on its tariff income, the evidence at the trial de novo conclusively demonstrated that a TAPS Owner would not sell its interest in TAPS without the assurance that its affiliated oil from the Alaska North Slope could be shipped to market. . . .

Gleason Decision ¶ 114

Market Structure

Integrated Operations with Market Power

124. [F]or the evidence persuasively demonstrates that ANS producers would rebuild TAPS at a cost of billions of dollars to transport ANS petroleum products to market if TAPS was not in existence as of the lien dates. And the producers would replace TAPS not for the tariff income they might realize, but to monetize the approximately 7 to 8 billion barrels of proven reserves that were at the ANS as of the lien dates.

Gleason Decision ¶ 124

Market Structure

Integrated Operations with Market Power

549. As in the 2006 tax year litigation, the Court finds again that tariff income is not the primary driver of the economic value of TAPS under AS 43.56. As SARB has held, and as this Court has previously discussed in these findings, TAPS was not built or operated for tariff income, but to monetize the vast ANS reserves of the producer oil companies by bringing those reserves to market. In this regard Mr. Coulson, the President of BP Pipelines (Alaska) Inc. and the Chairman of the Owners' Committee for TAPS at the time, testified as follows:

Q: It's fair to say that TAPS was built by the producers?

THE WITNESS: Yes.

Q. And it's fair to say that TAPS was built - that the economic driver was the integrated economics of bringing the Alaska North Slope oil to market?

THE WITNESS: As I understand the history of TAPS, and indeed of most basin-opening developments, it's usually the resource owner that has to make the infrastructure development happen because of the risks associated with an undertaking like that.

Q. And the reason that the resource owner takes those risks is in order to monetize the resource and bring it to market, correct?

THE WITNESS: Yes.

Market Structure

Integrated Operations with Market Power

551. [T]he Owners' reliance upon the tariff income approach fails to recognize that TAPS was built, is operated, and would be replaced at an estimated cost of approximately \$19 billion if it were not in existence, not because of a desire to realize tariff income, but because of the overwhelming economic value arising from its highly integrated use for transporting ANS production to market.

Gleason Decision ¶ 551

Market Structure

Integration – North Dakota

Testimony of Mr. Barry E. Sullivan (Munis' witness)

Q. And do you have a ... comparative sense between the TAPS system and other systems with regard to access for that independent shipper?

A. [I]n North Dakota, there's a new field called the Bakken field and it's ... a fairly hot area of exploration and development.

There's Enbridge Pipeline in the Bakken that has about 180 different shippers, and there are numerous marketers operating within that area that will buy and sell oil for you....

That contrasts with the situation on the North Slope where ... the producers themselves, the Big 3, do not sell oil at the North Slope and you can't buy oil at Pump Station 1 and transport it on TAPS. The policy of the Big 3 is to sell delivered oil in delivery markets.

Tesoro is the only shipper that's been able to buy North Slope oil and ship it on the TAPS system. So I think there's a big contrast between the way that the North Slope market works and other producing regions in North America.

2007-2009 Trial Tr. 8562-63

Market Structure

Integration – Gulf of Mexico

Testimony of Mr. Barry Sullivan (Munis' witness)

[I]f you compared what's happened in the North Slope of Alaska to the offshore Gulf of Mexico, which ... began, real exploration, probably back in the 1960s... you could look at the Gulf of Mexico today and it is an extremely competitive and well-explored area with numerous production companies and probably hundreds of different owners and producers that contrasts dramatically with what's happened in the North Slope.

And you don't have the level of competition on the North Slope that should be there after 35 years.

And I believe part of that is the vertical -- part of that can be caused by the vertical integration of the TAPS Carriers and their ownership of TAPS.

2007-2009 Trial Tr. 8556-58

Market Structure

Integrated Operations with Market Power

Testimony of Mr. Michael J. Remsha (Owners' witness)

Q. Okay. It is very simple. Let me go back to my hypothetical. Do you believe that the TAPS Owners would sell me TAPS for \$20 billion for the expressed purpose of shutting it down?

A. Most likely not.

Q. Why not?

A. Because they want to be able to have the opportunity to take oil from the North Slope and bring it to market.

2007-2009 Trial Tr. 692

Market Structure

Stages of Development

- Role of Majors / Role of Independents
- ANS Oil Development
- ANS Gas Development
- Cook Inlet Development
 - Open Infrastructure (Agrium)
 - Limited Open Market (Enstar & Export)
 - Tax Policy

Market Structure

Barriers to Competitive Entry

- Access to Field Facilities
 - ARCO Merger Partial Opportunity
 - Telecommunications Industry Example
- Transportation by Common Carrier Pipelines
 - History of TAPS Rates
 - Tariff Provisions
 - Restrictions on New Shippers
 - Tankage Penalties
- Transportation by Tankers

Market Structure

Barriers to Competitive Entry

561. Historically, regulatory disputes concerning TAPS' tariff rates have most often been resolved by settlement among the parties rather than by a substantive determination by FERC or the RCA. The settlement that has governed TAPS' tariff rates for the majority of the time it has been in service has been the TAPS Settlement Agreement ("TSA"). The TSA contained a complex and unique rate methodology referred to as the TSM. Both the State and the TAPS Owners supported the TSA. An Explanatory Statement by the State of Alaska and the Department of Justice in support of the settlement stated, "Alaska and DOJ believe that as a settlement, the tariff stream produced by the TSM is a fair and reasonable attempt to achieve a tariff profile that will encourage economically efficient exploration of North Slope petroleum resources."

Gleason Decision ¶ 561

Market Structure

Barriers to Competitive Entry

562. The RCA found that under the TSM, between 1977 and 1996, the TAPS Owners collected, in 1997 dollars, \$13.5 billion more than would have been collected under the current rate methodology used by the RCA to set rates on TAPS. Nevertheless, the TSM was approved by FERC.

Gleason Decision ¶ 562

Market Structure

Barriers to Competitive Entry

TAPS Settlement Methodology (TSM)

RCA Order 151:

<http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=03D92432-C32B-4C77-A47A-5705B899FC10>

FERC Opinion 502:

<http://www.ferc.gov/whats-new/comm-meet/2008/061908/G-1.pdf>

Market Structure

Source Materials

- Cicchetti Report (MUN7-0001)
- Sullivan Report (MUN7-0008)
- BP Tariff Memo (MUN7-0001 at 2455)

The Life of TAPS

Overview

- Price of ANS Crude Oil
- Reserves and Throughput
- Minimum Throughput

The Life of TAPS

Price of ANS Crude Oil

- Price Increases / Throughput Declines
- Value of Reserves / Engineering Solutions
- EIA Forecasts
- Real Price Growth

The Life of TAPS

Price of ANS Crude Oil

The EIA Price Forecasts Support Increasing Per Unit Throughput Value

- The Energy Information Administration (EIA) collects and publishes historic information and makes short- and long-term price forecasts
- Price Trends are up with increasing world demand.
- Since adopting NEMS in 1994, virtually all the future reference price forecasts post 1999 have underestimated actual crude prices
- Turning points follow crises, spare capacity, and worldwide demand/supply

The Life of TAPS

Price of ANS Crude Oil

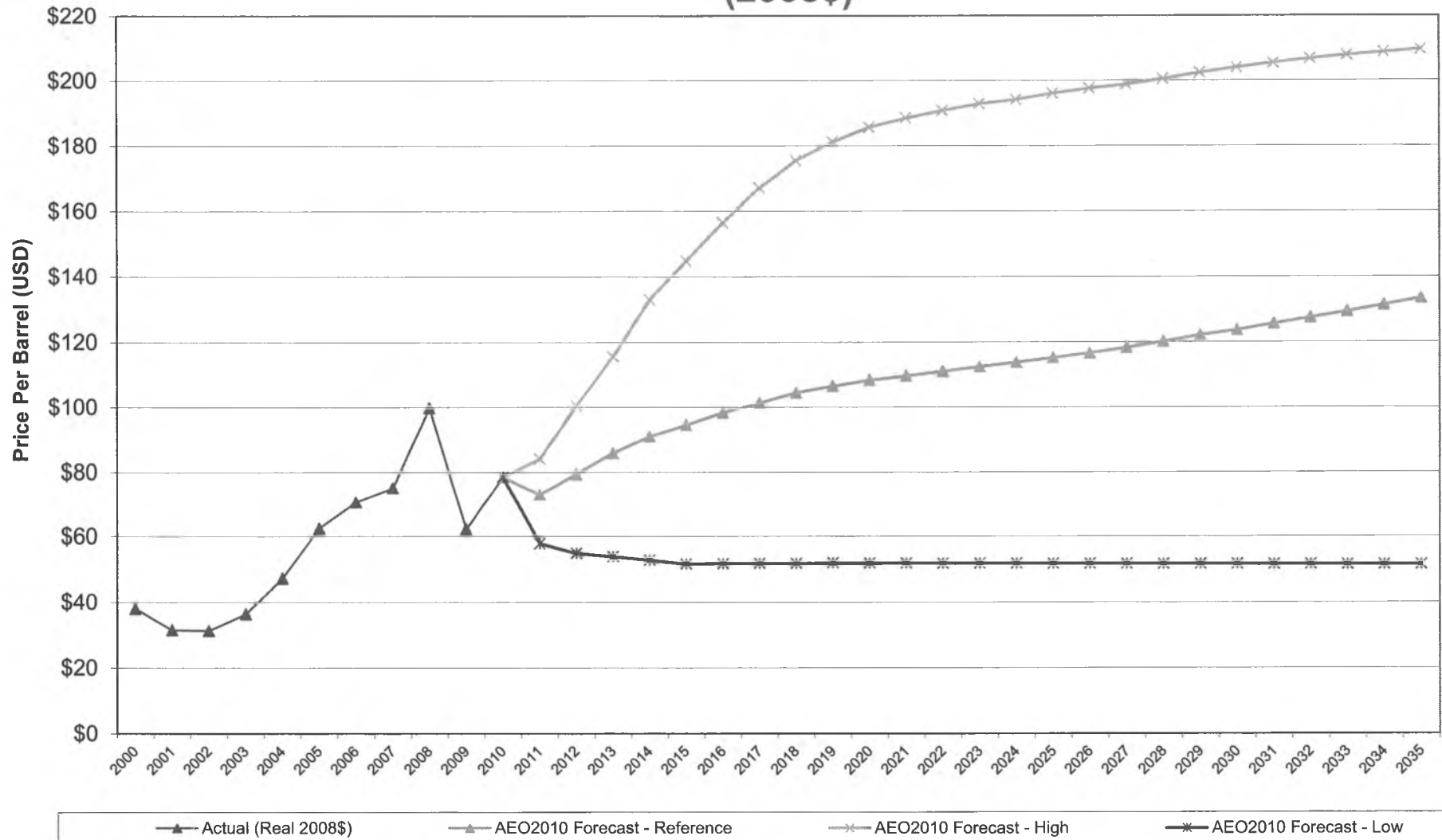
480. Mr. Platt relied upon the U.S. Department of Energy's Energy Information Administration ("EIA") price forecast, which forecasted real market price growth for each of the three assessment years at approximately 1% per annum. Based on the evidence presented at trial, this Court finds that reliance on that forecast was reasonable. Oil prices during the three assessment years were volatile, such that the forward-looking projections made by the EIA during that period varied considerably. Yet the highest oil price forecasted by the EIA for calendar year 2011 during the assessment years was \$74.08 per barrel, while the actual price of oil on October 18, 2011 was \$113 per barrel. Mr. Platt also explained that due to the highly progressive nature of Alaska's production tax, oilfield economics at high real oil prices are not materially affected by price variations. Overall, this Court found Mr. Platt's production forecast and economic testing to be persuasive.

Gleason Decision ¶ 480

The Life of TAPS

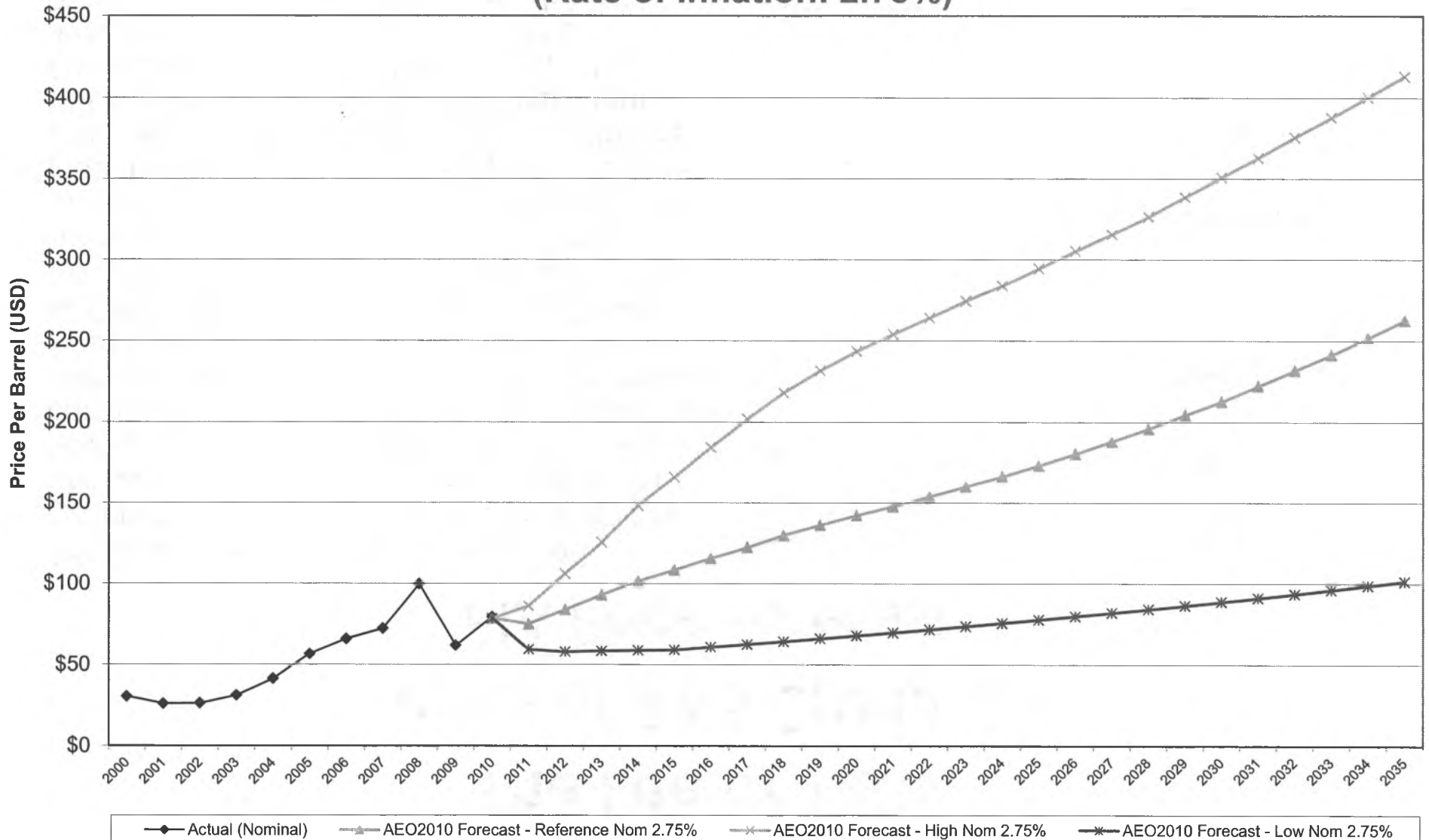
Price of ANS Crude Oil

Real Actual and Forecasted Crude Oil Spot Prices
Annual Average Price Per Barrel 2000-2035
(2008\$)



The Life of TAPS, Price of ANS Crude Oil

Nominal Actual and Forecasted Crude Oil Spot Prices Annual Average Price Per Barrel 2000-2035 (Rate of Inflation: 2.75%)



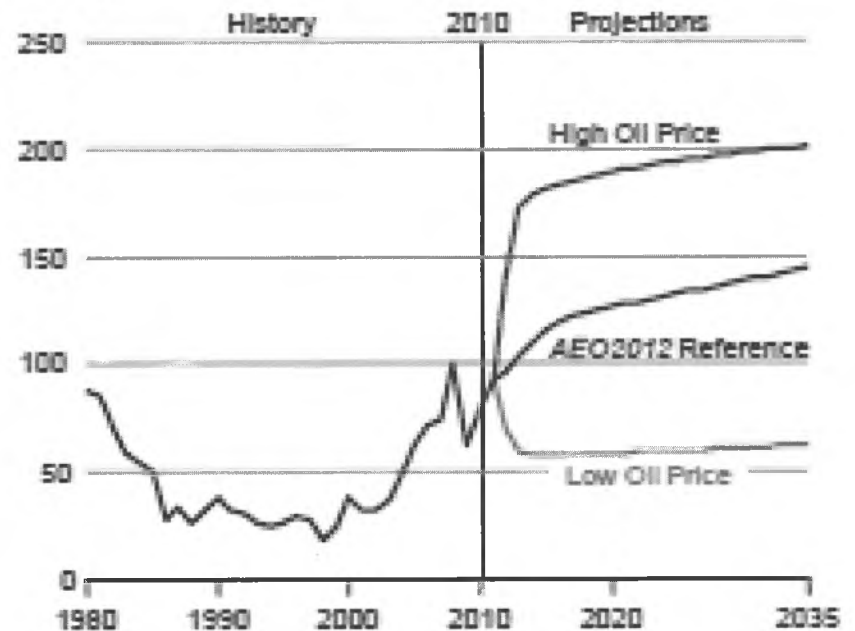
The Life of TAPS

Price of ANS Crude Oil

EIA Price Forecast

Prices for crude oil in 2011 remained generally in a range between \$85 and \$110 per barrel. In 2011, WTI prices were lower than Brent prices because of pipeline capacity constraints that prevented complete arbitrage between WTI and Brent prices. Real imported sweet crude oil prices (2010 dollars) in the AEO2012 Reference case rise to \$120 per barrel in 2016 (Figure 5) as pipeline capacity from Cushing, Oklahoma, to the Gulf Coast increases, the world economy recovers, and global demand grows more rapidly than the available supplies of liquids from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil in the Reference case is about \$145 per barrel in 2010 dollars, or about \$230 per barrel in nominal dollars.

Figure 5. Average annual world oil prices in three cases, 1980-2035 (real 2010 dollars per barrel)



[http://www.eia.gov/forecasts/aeo/er/pdf/0383er\(2012\).pdf](http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf)

The Life of TAPS

Reserves and Throughput

- Judge Gleason's Decision as to the Life of TAPS is Based on a Limited Definition of Proved Reserves Only and Does Not Consider Probably, Possible, or Speculative Categories
- Proven Reserves Were 9.6 Billion Barrels (1977) and are 7-7.8 Billion Barrels (2007-09) / Approximately 16 Billion Barrels Produced
- Value of Reserves Has Increased Substantially / Life Linked to Value (Increase of \$10 Barrel = 5.5 Years for TAPS)
- Internal Information / Financial Information Support Longer Life for TAPS

The Life of TAPS Reserves and Throughput

In August 2007, DOE and the National Energy Technology Laboratory (NETL) Reported “Economically Recoverable” Reserves at High Prices and With Natural Gas Development*

	(2005-2050) Billion Barrels
Total	35-36
Without ANWR 1002	29.5
Without ANWR 1002 and Chukchi Sea	19.5
Without ANWR 1002, Chukchi Sea and Beaufort Sea	15.5
Without ANWR 1002, Chukchi Sea, Beaufort Sea, and No Natural Gas Development	9.5

***The DOE/NETL issued an Addendum to this Report in April 2009 with the same estimates.**

The Life of TAPS

Reserves and Throughput

Value of Remaining Crude for the Next 25 Years Will Exceed
Current Cumulative Value of Oil Shipped

Cumulative Value of TAPS Through 2010

Barrels	16.3 billion barrels
Nominal Value	\$451.6 billion
Real Value (2008\$)	\$740.7 billion

Future Value of TAPS: 2011 Through 2035

	Low *	High + Beaufort Starting in 2016 *
	9.5 Billion Barrels Remaining	19.5 Billion Barrels Remaining
Barrels	5.9 billion barrels	10.9 billion barrels
Nominal Value	\$800.5 billion	\$1,539.6 billion
Real Value (2008\$)	\$593.5 billion	\$1,122.1 billion

Source of Prices: EIA Annual Energy Outlook 2010 Forecast Reference Prices
for Imported Crude Oil in Nominal\$ and 2008\$

*See DOE/NETL for volumes through 2050, prorated through 2035.

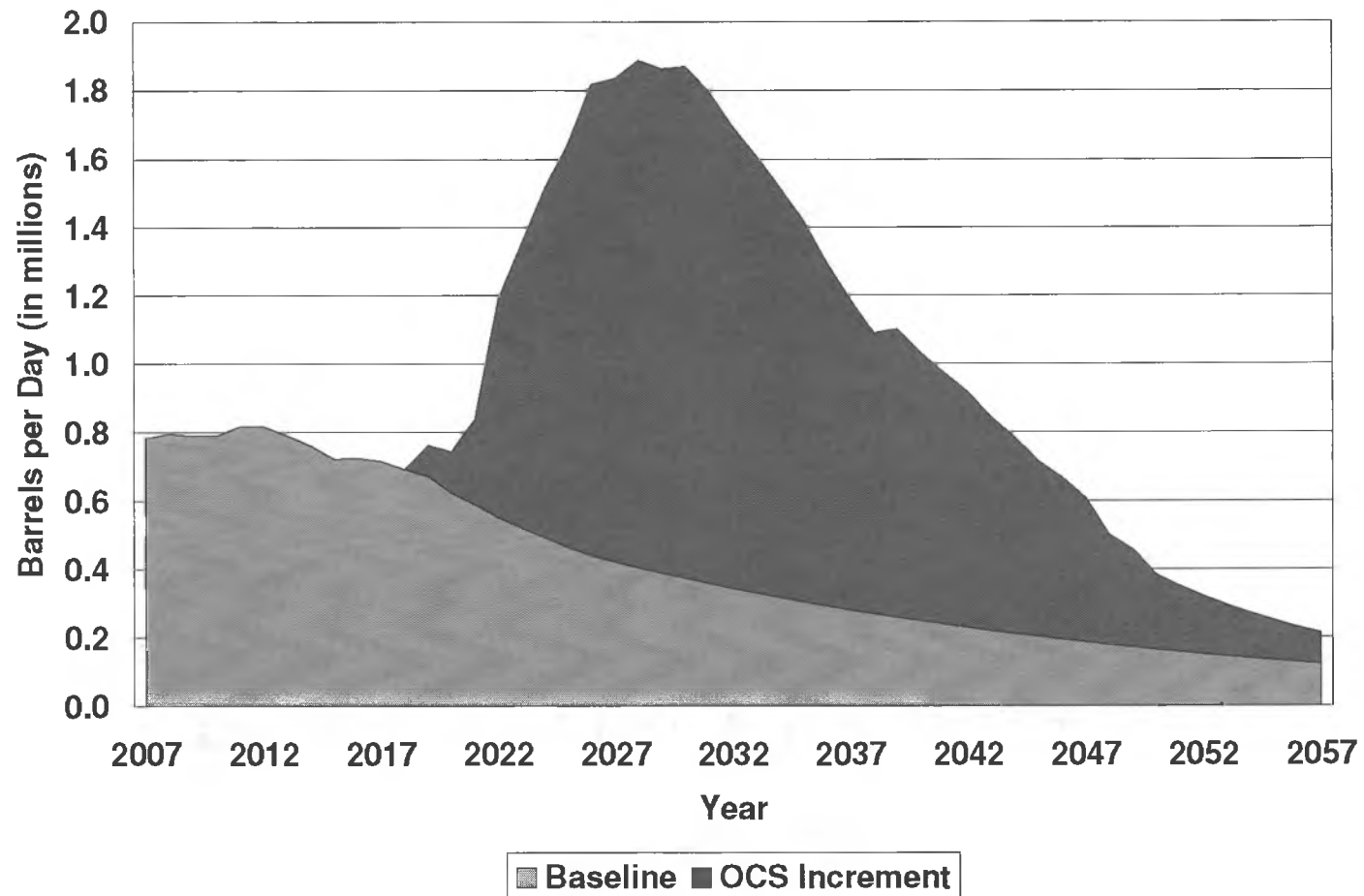
MUN7-9205 at 13

The Life of TAPS

Reserves and Throughput

Oil Production with OCS

MUN7-0653, Page 8 of 10



THE LIFE OF TAPS - Reserves and Throughput

Alaska North Slope Oil Production Forecasts
(Producing, Known Undeveloped, and Undiscovered)

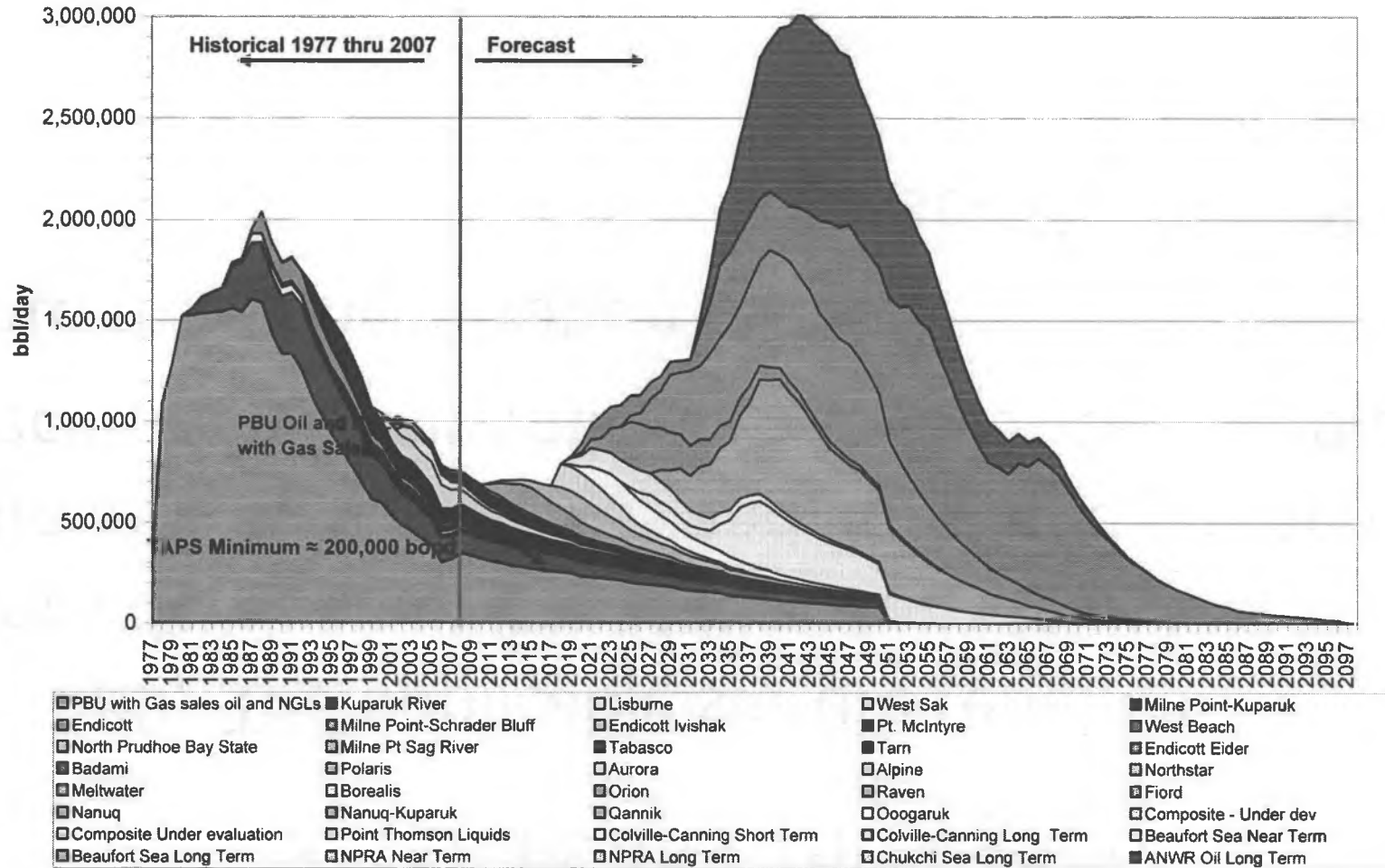


Figure 3-55. Alaska North Slope historical and forecast oil production from producing fields, known undeveloped fields, and undiscovered fields.

MUN7-0014 at 10 (Hite)

The Life of TAPS

Reserves and Throughput

439. The applicable statute requires consideration of the “estimated life of the proven reserves of gas and unrefined oil then technically, economically and legal deliverable into the transportation facility.”

Gleason Decision ¶ 439

The Life of TAPS

Reserves and Throughput

465. Dudley Platt is one of the preeminent production forecasters in the state, although he is not a petroleum engineer. He began making oil production forecasts for the State of Alaska in 1989. Mr. Platt prepared a production forecast for the Department every year through 2009. This Court relied on Mr. Platt's production forecast to determine TAPS' end-of-life in the 2006 tax year trial.

Gleason Decision ¶ 465

The Life of TAPS

Reserves and Throughput

468. Decline curve analysis is one component in the determination of the economic life of ANS proven reserves? Mr. Platt's forecast incorporated a decline curve analysis at the pool level, as opposed to a well-by-well analysis used by both the Owners' and Department's witnesses? Mr. Platt persuasively testified that, based on his experience working in the oil industry, long-range production forecasters do not use decline curves on a well-by-well basis? Mr. Van Dyke explained that well-by-well analysis can work well for a small lease in Kansas with four wells, but not for a field with 1,000 wells that are regularly being turned on and off: "it's not the best approach to use a well-by-well method as compared to the pool - a pool level method to forecast production." Decline curve analysis at the well level requires subjective analysis of highly variable historic data to estimate future production rates for each well.

Gleason Decision ¶ 468

The Life of TAPS

Reserves and Throughput

501. Overall, this Court finds that Mr. Molli's Fall 2010 forecast, and the Assessor's adjustments to that forecast for each tax year, are considerably less reliable than the production forecast prepared by the Municipalities' witness Dudley Platt.

Gleason Decision ¶ 501

The Life of TAPS

Reserves and Throughput

Pool v. Well-by-Well Forecasting

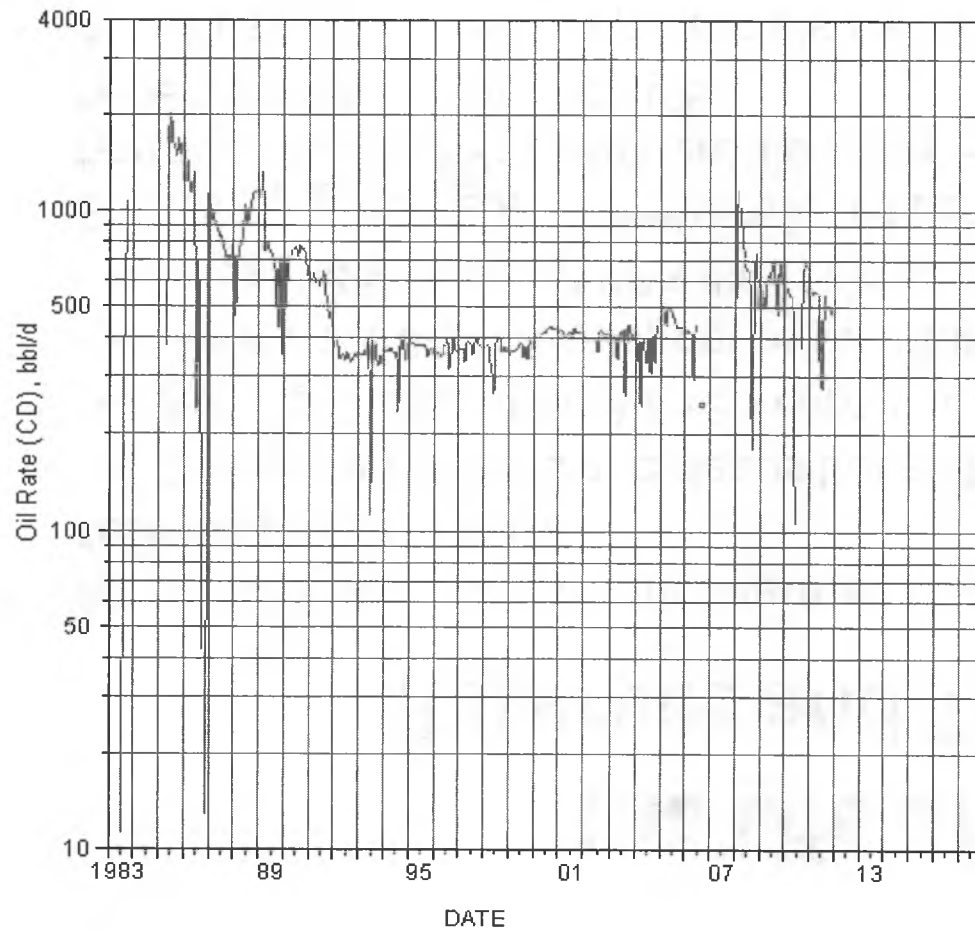
- In 2009 DOR changed from a pool to a well-by-well forecasting methodology
- “[A] pool based analysis is generally preferable to a well-based analysis.” [Gleason Decision ¶ 471]
 - Not relied on by industry
 - Fine “for a small lease in Kansas with four wells, but not for a field with 1,000 wells that that are regularly being turned on and off . . .” [Gleason Decision ¶ 468]
 - Good modeling does not look at wells on a standalone basis
 - Backward looking
 - Requires “subjective analysis of highly variable historic data to estimate future production rates for each well.” [Gleason Decision ¶ 494]
 - Often difficult to determine future performance of wells based on just historic data
 - Starts and stops, increasing production, etc.
 - DOR has historic data; it does not know of the story of each well
 - Not holistic, failing to reflect:
 - Industry estimates of oil in place or total recovery
 - Dynamic interaction of physical forces within reservoir, including interaction of wells
 - New projects and wells
 - Thus assumptions must be made about impacts on existing wells and new wells
 - When AS 43.56 enacted, DOR’s opinion was “it could be done more accurately on a field basis, as one well could dry up immediately.” [Gleason Decision ¶ 470]

The Life of TAPS

Reserves and Throughput

Example of Lisburne Well

L2-06



For other examples of wells that are difficult to forecast – see Platt Examples in documents provided

The Life of TAPS

Reserves and Throughput

- Municipalities pursued all avenues to get actual field models and reserves information
 - Discovery requests and depositions of Owners
 - Argued Owners had Rule 34 control over production affiliate information
 - Served third-party subpoenas on affiliate producers
 - Sought discovery of BP's data rooms for attempted 2010 sale
- Ended up getting a “patchwork” of reserves and production forecasts from primarily BP; Court would not permit production of BPXA's reserves economic models
- Most useful produced materials related to BPPA's transportation cost estimates for BPXA's reserves economics model
- The BPXA reserves and production estimates in BPPA's possession confirm the reasonableness of:
 - The total barrels recovered under Mr. Platt's forecast
 - The estimated end-of-life of Prudhoe Bay field determined by Mr. Platt and as reflected in the Prudhoe Bay Royalty Trust 10-K filings

The Life of TAPS

Reserves and Throughput

492. The internal reserves and long term production forecasting information that was made available through discovery was not reviewed by two of the Owners' reserves witnesses, Mr. Hartz or Mr. Marks, and only cursorily reviewed by Mr. Hoolahan (and not synthesized into his analysis). Further, Mr. Hoolahan did not have representatives of the Owners or their affiliated producers review his reserves estimates to provide feedback. This is despite the fact that the internal reserves information presented at trial was substantially different from Mr. Hoolahan's conclusions. The fact that none of the Owners' reserves experts meaningfully addressed the BP internal reserves information at trial had a substantial negative impact on the weight this Court accorded to their testimony.

Gleason Decision ¶ 492

The Life of TAPS

Reserves and Throughput

495. The determination of the estimated proven reserves should be assessed in light of the evidence available to, and presented by, each of the parties. The Owners did not persuasively rebut the Municipalities' evidence regarding proven reserves, including information contained in filings by the BP Royalty Trust and the confidential reserves information produced in discovery.

Gleason Decision ¶ 495

The Life of TAPS

Reserves and Throughput BP Royalty Trust End-of-Life

- The BP Prudhoe Bay Royalty Trust is a publicly traded trust that has a royalty interest in certain BP production
- Each year BPXA provides the Trust and their auditors, Miller and Lents, Ltd., with reservoir, production and other information
- In the past the Trust's 10-K included BPXA's opinion as to the end-of-life of Prudhoe
- "BP Alaska expects continued economic production from Prudhoe Bay field at a declining rate through 2075." [MUN7-4072 at 13]

The Life of TAPS

Reserves and Throughput

502. BP Exploration (Alaska), an affiliated company of one of the taxpayers in this case, BP Pipelines, provides SEC reserves information on the Prudhoe Bay field each year to the BP Prudhoe Bay Royalty Trust. The information is audited by an independent oil and gas consultant, Miller and Lents, before submission to the SEC. The Trust's SEC filing for year-end 2005, using the SEC's heightened "reasonable certainty" standard for proven reserves, represented that "BP Alaska expects continued economic production [from Prudhoe Bay] at a declining rate until the year 2065" In the year-end 2006, 2007 and 2008 SEC 10-K filings, BP represented continued economic production at Prudhoe Bay until 2062, 2075 and 2049, respectively. The 2049 economic end-of-life calculation for December 31, 2008 was based on the price of oil on that date of \$44.60, while the December 31, 2006 economic end-of-life date was based on an oil price of \$61.06. Both of these amounts were considerably below the average price of oil during those years and its predicted future price. The 2007 filing was based on the price of oil on December 31, 2007 of \$96.01.

Gleason Decision ¶ 502

The Life of TAPS

Reserves and Throughput

503. The following chart sets out the assumed end-of-life in the Prudhoe Bay Royalty Trust SEC filings and as calculated by each of the parties' experts.

Comparison of Prudhoe Bay End-of-Life Determinations

	CY 2007	CY 2008	CY 2009
IPB Royalty Trust	2062 ⁸³⁷	2075 ⁸³⁸	2049 ⁸³⁹
Muni @ 100,000 bbl/d	2067 ⁸⁴⁰	2066 ⁸⁴¹	2068 ⁸⁴²
Muni @ Economic Limit	2075 ⁸⁴³	2075 ⁸⁴⁴	2075 ⁸⁴⁵
SOA @ 150,000 bbl/d	2040 ⁸⁴⁶	2040 ⁸⁴⁷	2040 ⁸⁴⁸
SOA @ Economic Limit	2043 ⁸⁴⁹	2044 ⁸⁵⁰	2053 ⁸⁵¹
Hoolahan – Initial	2026 ⁸⁵²	2033 ⁸⁵³	2021 ⁸⁵⁴
Hoolahan – Corrected	2046 ⁸⁵⁵	2053 ⁸⁵⁶	2032 ⁸⁵⁷

Gleason Decision ¶ 503

The Life of TAPS

Reserves and Throughput BP Royalty Trust End-of-Life

- The estimated end-of-life has varied each reporting year based on the price of oil
- From as low at 2049 in 2009 to as high as 2075 in 2008
- There is a strong correlation that for every \$10 increase in oil prices, the economic life of Prudhoe Bay increases about 5.5 years [MUN7-0001 at 15-16 (Cicchetti)]

The Life of TAPS

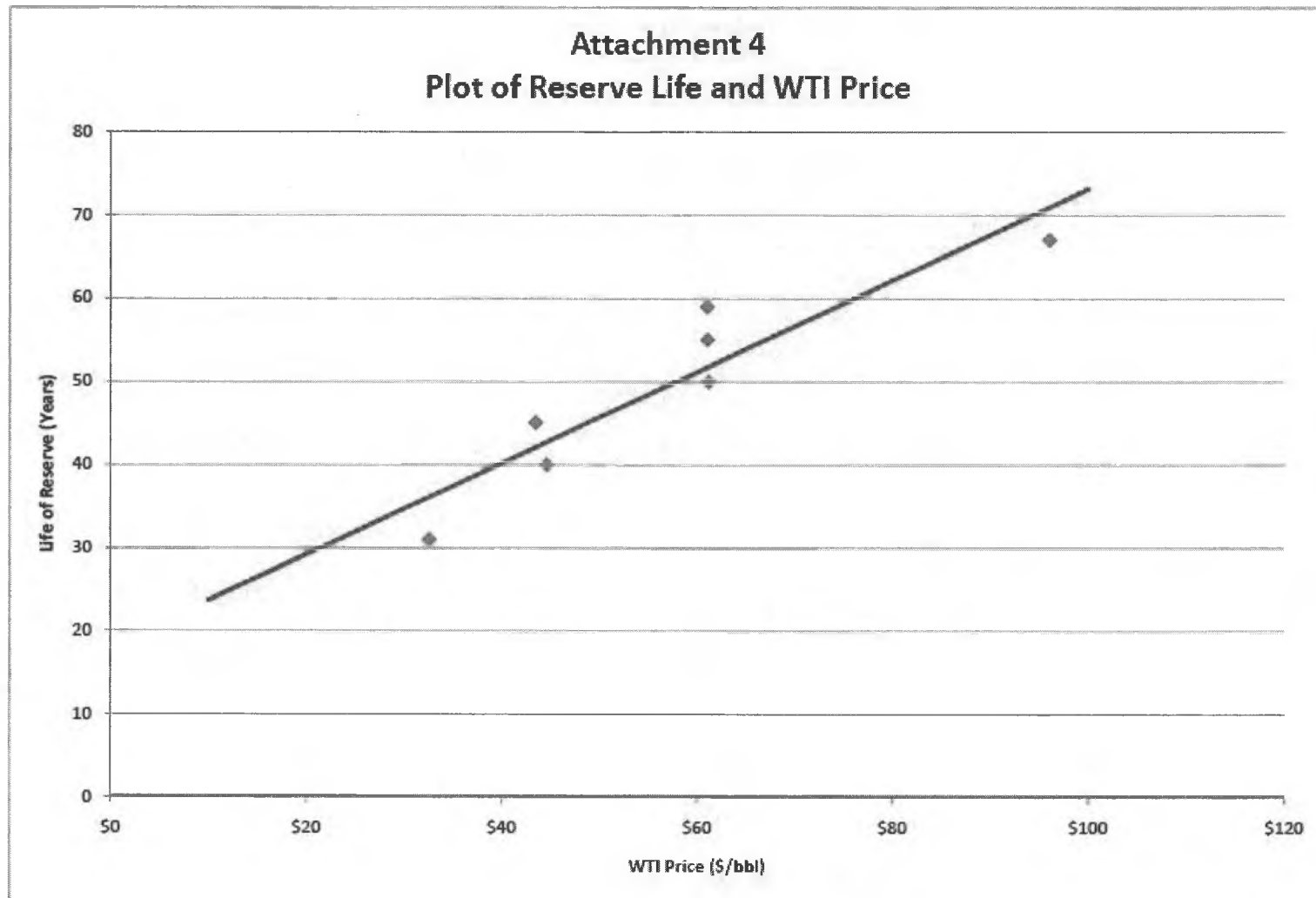
Reserves and Throughput

24. I prepared a chart and some simple regressions in Attachment 4 to show the relation between economic life and WTI prices that BP relies upon in its various recent SEC 10-K filings. I plotted the relationship between the estimated life of the Prudhoe Bay reserves and WTI year-end prices. In particular, I found that for every \$10 increase in year-end WTI prices, the economic life of Prudhoe Bay increases about 5.5 years. (See the linear regression in Attachment 4.)

MUN7-0001 at 15-16 (Cicchetti)

The Life of TAPS

Reserves and Throughput



The Life of TAPS

Reserves and Throughput

506. With Point Thomson removed from Mr. Platt's corrected reserves estimates for 2007 and 2009, the total proven reserves for each of the lien dates is as follows:

2007 7.812 billion barrels

2008 7.759 billion barrels

2009 7.077 billion barrels

Gleason Decision ¶ 506

The Life of TAPS

Reserves and Throughput

- ANS will continue to economically produce oil, as demonstrated by BP, through 2075 based only on proved reserves
 - Assuming a minimal mechanical capacity of 100,000 bbl/d, the Court found the end-of-life of TAPS given current proved reserves is at least 2066. [Gleason Decision ¶ 505]
- Life of the ANS is even longer when production from heavy oil, ANWR, OCS, and other non-proved sources is considered

The Life of TAPS

Minimum Throughput

- Hydraulic Limit (None)
- Mechanical Limit (Less than 50,000 BPD)
- Operational Concerns (Solutions)
 - Temperature, Wax, Pigging, etc.
 - No Pipeline has Shut in Economic Production
 - Value of Oil Behind Pipe Dominates Solutions
 - 300,000 BPD to 100,000 BPD = 2 Billion of Proved Reserves
 - Engineering Solutions to Low Flow is Pennies / Value of Transporting Oil to Market is Dollars
 - Engineering Solutions Are Apparent

The Life of TAPS

Minimum Throughput

- **Alaska law doesn't contemplate a mechanical limit**
 - AS 43.56.060(e)(2) and 15 AAC 56.110(c) state life of operating pipelines to be “based on the estimated life of the proven reserves”
- **Economic life of other taxable pipelines in Alaska based on life of proven reserves, not a mechanical limit** [2007-2009 Trial Tr. 11565 (Hoffbeck)]
- **Common sense and expert testimony demonstrate no otherwise economic pipeline has shut in at 100,000, 50,000 BPD or below** [2007-2009 Trial Tr. 5130-31 (Riordan); Tr. 8266-68 (quoting Coulson Deposition); Tr. 11895 (Remsha)]
 - Proof is in the Tasting—No pipeline in the history of man has shut-in economic production due to pipeline operational concerns (Example: CIPL)
- **BP has identified engineering solutions to operate TAPS at ultra low flows**
 - Heating gets you to 70,000 BPD; below that options like fluid injection (to get flow rates up) will be identified as needed [MUN7-3020 at 8]
 - “When coupled with the fact that there is a practical limit to the number of heater locations be added, 50,000 BPD to 70,000 BPD is probably the [low flow] limit to [point source heating] due to wax deposition and pigging concerns. Further reduction in flow will require investigation of other options that maintain higher flow velocities, such as seawater commodity supplementation.” [MUN7-3020 at 8]
- **Thus state law, Alaska tax practice for other pipelines, industry experience, and BP's own reserves booking contemplate no identifiable mechanical limit**

The Life of TAPS

Minimum Throughput

401. The Municipalities' expert Dr. Jerry Modisette testified that there is no hydraulic or mechanical minimum throughput limit because the pipeline will be within pressure constraints at flows down to zero and the pump rate can also go down to zero through reducing pumps, throttling, and recirculation. Former Alyeska Chief Operating Officer Dan Hisey concurred that there is no hydraulic or mechanical minimum throughput limit on TAPS. The Owners' expert, Ulli Pietsch, also testified that there is no hydraulic or mechanical reason that TAPS cannot operate down to 50,000 bbl/d. The inquiry therefore turns to whether there is an operational constraint that would prevent TAPS from transporting oil at some minimum capacity limit.

Gleason Decision ¶ 401

The Life of TAPS

Minimum Throughput

Testimony of Mr. Ulli Pietsch (Owners' Witness)

Q. I'm going to make this very simple. I want to ask you questions. I'm going to ask you questions in three buckets: Hydraulically, mechanically, and operationally.

A. Okay.

* * *

Q. So there is no reason that TAPS cannot hydraulically operate at a teaspoonful a day, correct?

A. Correct.

* * *

Q. Is there any mechanical reason, that assuming a proper recirculation system is in place, that TAPS cannot operate at 50,000 barrels a day?

A. No.

* * *

Q. Okay. So hydraulically and mechanically, there is no reason that TAPS, as it currently exists, cannot operate down to 50,000 barrels a day, assuming recirculation?

A. Correct.

The Life of TAPS

Minimum Throughput

404. BPPA analyst John Haines testified at the trial in this case. In an email dated November 5, 2004, Mr. Haines stated:

Momentum is starting to grow around booking more reserves based on an updated view of TAPS' minimum achievable rates ... Lastly, when TAPS rates reach 100 MBD [100,000 bbl/d] we stop. Our consultant thinks we can probably operate TAPS below this minimum rate, but we didn't want to push it any further at this time.

Gleason Decision ¶ 404

The Life of TAPS

Minimum Throughput

409. In its initial year-end 2004 reserves submission to the BP London office, which was scheduled a couple of months before the JTG Study was concluded, BP Exploration and BP Pipelines personnel determined “an effective TAPS minimum throughput level of 150,000 bbl/d at 2053,” using “conservative assumptions.” The report added:

In the case of GPB [Greater Prudhoe Bay] and KRU [Kuparuk River Unit] (the biggest contributors to the reserves adds) each of these fields were still cash flow positive at 2064 (end of our tariff profile). The reserves coordinators arbitrarily chose to cut-off life at the earlier dates (2053 for GPB and 2047 for GKA) just to give themselves some future cushion.

Gleason Decision ¶ 409

The Life of TAPS

Minimum Throughput

406. In 2004, BP Pipelines retained JTG Technology Consortium to conduct a study to revisit the minimum throughput limit on TAPS, The 308-page JTG report was completed in 2005 (“JTG Study”) and concluded that “the low flow limit of the existing 48-inch TAPS pipeline was determined to be a PS [Pump Station] 1 rate of 135 MB/day [135,000 bbl/d].”

Gleason Decision ¶ 406

The Life of TAPS

Minimum Throughput

408. BPPA and its affiliates relied upon the JTG Study's conclusion of a 135,000 bbl/d low-flow limit to create tariff profiles that BP then used to report its reserves for several years to the SEC.

Gleason Decision ¶ 408

The Life of TAPS

Minimum Throughput

412. BP Pipelines failed to provide the 2005 JTG Study in discovery for the 2006 ad valorem tax year proceedings. That study would have supported the Municipalities' position in that litigation that TAPS could operate down to 150,000 bbl/d or less, and may well have resulted in the Court finding a minimum capacity limit lower than the 200,000 bbl/d that this Court applied for that assessment year.

Gleason Decision ¶ 412

The Life of TAPS

Minimum Throughput

414. In 2010, BP Pipelines retained Phil Carpenter, a subject matter expert who was also used extensively by Alyeska in its Low Flow study, to determine whether TAPS could operate at levels below the 135,000 bbl/d threshold put forth in the 2005 JTG Study. At trial, Mr. Haines of BP Pipelines explained:

The JTG study ... essentially had two different paths that you could live with ... One path was you would throw investments at TAPS and eventually the south leg would die at a rate of 135. You would start a railroading apparatus at that point. ... the south leg always died first because of the extraction of oil at Fairbanks at the Fairbanks refinery ... Except if you wanted to throw another \$3 billion at the problem and replace the north leg with a replacement 20-inch line ... [so as to be able to transport down to 45,000 bbl/day] ... And the economic hurdle of paying for that \$3 billion of replacement line investment created a very large stair-step in the economic profile, the granularity I was talking about.

Gleason Decision ¶ 414

The Life of TAPS

Minimum Throughput

415. In a May 19, 2010 email, Mr. Haines provided Mr. Carpenter with a copy of the 2005 JTG Study and explained:

You probably want to start with the executive summary. As we discussed on the phone, our reserves reporting relied on a 'low oil Price' scenario and a 'high oil price scenario.' These are identified in the report as Scenario 2 and Scenario 3. What we are looking for in your work effort is some sort of intermediate solution that could be used to extend the limit beyond 135 MBD [135,000 bbl/d] (Scenario 2), but would not have a \$3 billion hurdle that would allow us to get down to 45 MBD [45,000 bbl/d]. In other words, something for a "middle oil price" scenario.

Gleason Decision ¶ 415

The Life of TAPS

Minimum Throughput

416. A June 11, 2010 email from Mr. Carpenter contained a list of over a dozen low throughput options he had analyzed. On June 15, 2010, Mr. Haines responded back that:

I've had a chance to talk to our upstream reserves guys, and they advise that Option 2 (run cold and sweep with freeze suppressant) sounds like it might be pushing things too far, because it requires achieving a level of confidence in the physics of the problem - a level of "proof" that our study will not be capable of fully defining. So, they agree we can drop it from the list

Mr. Haines then discussed the various other options, concluding:

From a pragmatic viewpoint, it seems to me that item 1 (heaters) may be exactly what we're looking for (in terms of finding a sure-fire way to bridge between the 135 MBD [135,000 bbl/d] endpoint and the large capital cost of replacing the north leg). I say this because if we can find a way to lower the endpoint from 135 MBD [135,000 bbl/d] to say something in the range of 100 MBD [100,000 bbl/d] or less, that kind of solution would probably act to close the gap our reserves guys are seeking.

The Life of TAPS

Minimum Throughput

418. Consistent with that opinion, on July 20, 2010, Mr. Carpenter circulated a draft of the 2010 Carpenter Study: “The analysis concluded that point source heating of the oil is the best solution for operation of 100,000 [bbl/d].” Mr. Haines’ response to the draft stated:

Thanks for the updated report. This is shaping up nicely, and is exactly the “fit for purpose” product we were looking for. ... Probably the most significant edits we’ve made to your most recent draft involved turning on the railroad when the PS-1 rate hits 140 MBD [140,000 bbl/d] (and turning off the south leg), and running the north leg down to 70 MBD [70,000 bbl/d]. This means some of the south leg heaters will likely not be installed at rates below 140 MBD [140,000 bbl/d] (because of laminar flow issues).

Gleason Decision ¶ 418

The Life of TAPS

Minimum Throughput

420. The 2010 Carpenter Study did not foreclose lower throughput levels below its conclusions, acknowledging that other technologies apart from point source heating “may eventually offer better solutions with fewer unknowns, lower throughput limits and lower shutdown risk, but these options are less developed and well understood at this time.” The Study stated that “50,000 [bbl/d] to 70,000 [bbl/d] is probably the limit for [the point source heating] approach due to wax deposition and pigging concerns. Further reduction in flow will require investigation of other options that maintain higher flow velocities, such as seawater commodity supplementation.”

Gleason Decision ¶ 420

The Life of TAPS

Minimum Throughput

422. In the fall of 2010, BPPA used the lower minimum throughput determinations from the Carpenter Study in its transportation tariff calculations. Those calculations, in turn, were provided to BP Production forecasting personnel who then used that information to book BP's proven reserves in 2010. That BP relied upon the Carpenter Study's 100,000 to 70,000 bbl/d low flow estimate to book its reserves is compelling evidence that these figures may be reasonably relied upon by this Court to determine the assessed value of TAPS.

Gleason Decision ¶ 422

The Life of TAPS

Minimum Throughput

The Studies: Alyeska LoFIS

- The Alyeska Low-Flow Impact Study (LoFIS) was limited in scope: “Flow volumes of less than about 350,000 BPD subject TAPS operations and pipeline integrity to greater degrees of uncertainty that require investigation and study beyond that accomplished through the LoFIS. Measures to mitigate these issues utilizing the existing 48-inch pipe at throughputs below 350,000 BPD have not been determined at the date of this report.”

[Executive Summary of LoFIS Final Report (public version, June 15, 2011) at 3]

- Mr. McDevitt’s deposition and trial testimony confirmed that the LoFIS team was subject to a 300,000 bbl/d limit. [2007-2009 Trial Tr. 10975-82] Mr. Haines also confirmed the limitation. [2007-2009 Trial Tr. 11404]

The Life of TAPS

Minimum Throughput

Alyeska Cannot Show A 300,000 bbl/d Limit

- Mr. McDevitt stated at trial that it was not possible for TAPS to operate under 300,000 bbl/d, but later changed his answer to “highly unlikely” when asked in the context of BP’s booking practices. [2007-2009 Trial Tr. 11025-27, 11093]
- Mr. Carpenter was a subject-matter expert for water transport, hydraulic size formation and heat transfer in the Alyeska LoFIS team while he conducted his study for BP. [2007-2009 Trial Tr. 10960-61]
- Mr. Riordan testified that he did not know for a fact that the existing facility cannot operate at 100,000 bbl/d. [2007-2009 Trial Tr. 5129]

The Life of TAPS

Minimum Throughput

430. This Court finds the JTG and Carpenter studies, which were conducted by TAPS' largest Owner for the specific purpose of evaluating the ability of TAPS to operate at throughputs well below 300,000 bbl/d and relied upon by BP for booking its proven reserves, to be far more persuasive than the LoFIS study in determining TAPS' minimum throughput capacity.

Gleason Decision ¶ 430

The Life of TAPS

Minimum Throughput

431. At trial, the Municipalities' expert Dr. Jerry Modisette persuasively opined why he had determined that TAPS could operate at 100,000 bbl/d. Indeed, Dr. Modisette asserted TAPS could operate at far lower throughputs than that, particularly if the oil were recirculated through the pumps so as to raise its temperature - a project Alyeska is planning to try this winter.

Gleason Decision ¶ 431

The Life of TAPS

Minimum Throughput

432. With regard to the low-flow operational issues identified in the Alyeska study, including water dropout and corrosion, ice formation within the crude oil, ice lenses or frost heaves in the soil, and wax precipitation and deposition, the weight of the evidence at trial persuaded this Court that it is more likely than not that there will be engineering solutions to mitigate these problems on TAPS at throughputs down to 100,000 bbl/d or less.

Gleason Decision ¶ 432

The Life of TAPS

Minimum Throughput

The Operational Issues Can Be Mitigated

Hisey
Chart

Issue/Concern	Mitigation Measures Available															
	Water			Heat			Pigging						Chemical Treatment			
	Lower Spec Limit	Remove	Improve Monitoring Capability	Recirculate	Point Source	Add, Repair, Replace Insulation	Increase Frequency	Add Launchers Receivers	Divert Incoming Stream	Install Washers	Modify Cleaning Pig Design	Modify Operating Procedure	Corrosion	Freeze Point	Emulsion	Wax Point
Wax																
pipe wall deposit				X	X	X	X	X		X	X				X	X
instrumentation	X	X	X	X	X	X								X	X	X
smart-pig data				X	X	X	X	X			X					X
cleaning volume				X	X	X	X	X	X	X	X				X	X
Ice																
equipment damage	X	X	X	X	X	X			X					X		
valve operation	X	X	X	X	X	X	X				X		X	X		
ice plugs	X	X	X	X	X	X	X	X			X		X	X		
Other																
Cold Restart	X	X	X	X	X	X						X		X	X	X
Frost Heave				X	X	X										
Increased corrosion	X	X	X				X	X					X	X	X	
Slack Line												X				
Crude Oil "gelling"				X	X	X									X	X

The Life of TAPS

Minimum Throughput

434. The August 2010 Larkspur Study estimates approximately \$2 billion in undiscounted costs for heating TAPS so as to be able to transport 100,000 bbl/d. This is based on the 2010 Carpenter Study's use of substantial redundancy resulting in 70% excess heating capacity. Thus, the actual cost could well be considerably lower. However, even Larkspur's estimated expense is self-evidently economic in light of the value of TAPS' proven reserves, The Court was persuaded by Mr. Hisey's testimony that even if the heating and other mitigation measures cost upwards of hundreds of millions of dollars in the coming decades, it would still be economical to make such investments to keep TAPS operating at and below 100,000 bbl/d "to move North Slope crude oil and keep that transportation base available for future fields, future production."

Gleason Decision ¶ 434

The Life of TAPS

Minimum Throughput

437. This Court finds the conclusions reached in the 2005 JTG study, together with the opinions reached in the 2010 Carpenter Study and Larkspur Study, as well as the opinions of Dr. Modisette and Mr. Hisey, to be more credible and persuasive than Mr. McDevitt's opinion on TAPS' minimum throughput capacity.

Gleason Decision ¶ 437

The Life of TAPS

Minimum Throughput

438. For the foregoing reasons, and after careful consideration of all of the evidence presented at trial, this Court finds it more likely than not that TAPS can effectively transport throughputs at least down to a minimum flow rate of 100,000 bbl/d.

Gleason Decision ¶ 438

The Life of TAPS

Minimum Throughput

Maximum Limit of 100,000 BPD

- Mr. Hisey testified that even hundreds of millions of dollars in heating and other low flow mitigation efforts are economic to keep TAPS operating at and below 100,000 bbl/d [2007-2009 Trial Tr. 9000]
- Dr. Modisette testified that the Texaco Cal 20 pipeline uses more heating per unit than the worst case heating scenario for TAPS [2007-2009 Trial Tr. 9061-63]
- No witness was aware of a pipeline that shut in production for operational reasons when it was flowing economic oil [2007-2009 Trial Tr. 674 (Remsha); Tr. 5130-31 (Riordan); Tr. 8266-68 (quoting Coulson deposition); Tr. 9218 (Malvick); Tr. 11090 (McDevitt); Tr. 11895 (Remsha)]

The Life of TAPS

Minimum Throughput

Economics of Continued Operation

Forecast Year	Platt Production Rate Range (barrels/day)	Stranded Oil Volume Over Applicable Forecast Range	Average EIA Real Oil Price Forecast Over Applicable Time Period (per bbl)	Total Value of Stranded Oil
2009	300,000 to 100,000	2.0 billion bbl	\$169.06	\$338,120,000,000
	200,000 to 100,000	1.2 billion bbl	\$177.25	\$212,700,000,000
	150,000 to 100,000	0.7 billion bbl	\$183.30	\$128,310,000,000

SOURCES:

MUN7-4306, MUN7-4309, and MUN7-4313

MUN7-0017 p. 23

The Life of TAPS

Source Materials

- Platt Report (MUN7-0024)
- Platt Rebuttal Report (MUN7-0026)
- Hite Report (MUN7-0014)
- Van Dyke Report (MUN7-0017)
- Van Dyke Report Supplement (MUN7-0018)
- Unpredictable Wells Data
- BP Royalty Trust (MUN7-4072)
- JTG Report (MUN7-3000)
- Carpenter Study (MUN7-3020)
- Larkspur Study (MUN7-3044)
- Haines Testimony
- Modisette Report (MUN7-0028)
- Hisey Report (MUN7-0034)
- Hisey PowerPoint

Access to Information

- Relevant Statutes
- Department Will Not Use Subpoena Power
- The Department Overuses Taxpayer Confidential Designations
- Department Will Not Agree to a Joint Administrative Agreement

Access to Information

491. SARB observed the following in its Certificate of Determination for the 2007 assessment year:

The Board also found that the Owners failed to take advantage of the opportunity to provide the Division with persuasive data to challenge the reserves estimates or throughput projections used by the Division if the Owners have such data. The Board found that the Owners chose not to the [sic] share information that the Owners and their parent companies possess regarding throughput and proven reserves with the Division or the Board and instead chose to present evidence and testimony from outside experts who did not have access to the information the Owners possess that was not already in the public record, and who lacked adequate direct experience with, or expertise about, the TAPS or the Alaska North Slope reserves.

Gleason Decision ¶ 491

Access to Information

5. AS 43.56.080 grants the Division certain investigative powers when assessing AS 43.56 properties, including the power to “enter any premise necessary for the investigation during reasonable hours,” to “examine property and appropriate records,” and to compel owner representatives “to appear for examination under oath by the department.” There was no persuasive evidence presented at the trial de novo that the Division has ever exercised these powers with respect to the valuation of TAPS.

Gleason Decision ¶ 5

Access to Information

6. The Division broadly interprets what it considers “taxpayer confidential” information under applicable statutes and will not disclose such information to the Municipalities specifically or to the public generally. The Division considers all information that it receives from a taxpayer as “taxpayer confidential,” even if it does not contain the particularities of a taxpayer’s business affairs and is obtainable from the public domain. As a result, the Division did not provide the Owners’ new replacement cost study by Stantec Consulting, Inc. (“Stantec”) to the Municipalities.

Gleason Decision ¶ 6

Access to Information

7. AS 43.56.060(g) provides that “[t]he department may enter into agreements with a municipality for the cooperative or joint administration of the assessing authority conferred on the department by this section.” The North Slope Borough previously had such an agreement with the Department. The City of Valdez and Fairbanks North Star Borough have never been parties to joint assessment agreements with the Department.

Gleason Decision ¶ 7

Access to Information

8. In its 2010 decision, SARB expressed its concerns regarding the Division's assessment practices:

The Board believes that it is time for the Division to address the problems created by the way it handles taxpayer confidential information in the assessment process. The Division's failure to provide interested parties with the information on which the assessment was made in time to allow those parties meaningful input in the determination of the property's assessed value, before that determination is subject to limited review of an appeal before the Board, has the potential to throw the fundamental fairness of the AS 43.56 assessment process into question. The Board believes that, due to the Division's current practices with regard to the use of taxpayer confidential information in its AS 43.56 assessments, that process is close to broken and is headed in the wrong direction.

This Court concurs with the Board's observations in this regard.

Gleason Decision ¶ 8

Access to Information

Information at DOR Level

- History of TAPS Valuation
- DOR Process
- Access to Taxpayer Information
- Treatment of Taxpayer Information
- Consequence of Lack of Access to Information

Access to Information

History of TAPS Valuation

- DOR relying on TSM based rates lead the assessments falling from over \$8 billion in the mid-1980s to \$2.75 billion in 2001 [Gleason Decision ¶ 30]
- For decades the valuation of TAPS was a negotiated process that largely excluded the Municipalities
- The Municipalities fully engaged the process for the 2005 assessment

Access to Information

Observation About DOR's Process

- Key DOR staff are fair, dedicated, and highly competent
- The SARB has also been balanced and diligent
- However the DOR process—as related to information relied on in the taxation process—is close to broken. [Gleason Decision ¶ 8]

Access to Information

Access to Confidential Information

- Taxing authorities typically compel information
 - DOR can subpoena information, depose taxpayer representatives, and investigate property and records [AS 43.56.080; AS 29.45.130; AS 43.55.040(a)]
- DOR policy is to work cooperatively with industry, so it does not exercise these powers [Gleason Decision ¶ 8]
- Thus, DOR relies on information that a taxpayer volunteers or that is publicly available

Access to Information

Taxpayer Information

- The Alaska Public Records Act, AS 40.25.110, requires State documents to be subject to public examination
- Exception exists under AS 40.25.100(a) for tax information “that discloses the particulars of the business or affairs of a taxpayer” in which case the “information shall be kept confidential except when . . . required in an official investigation [or proceeding]”
- AS 43.05.230(a) also makes it unlawful to “divulge the amount of income or the particulars set out or disclosed in a report or return” except in conjunction with “investigations or proceedings”

Access to Information

Taxpayer Information

DOR narrowly reads taxpayer confidentiality statutes, denying public access to:

- All information provided by taxpayers
 - Non-sensitive correspondence, hypothetical studies, publicly available information, etc.
- Information provided for its production forecasting, which is a budgeting function [2007-2009 Trial Tr. 8813-14, Tr. 10874-877]
- The Municipalities
 - AS 43.56.060(g) allows for joint administration of taxes
 - North Slope Borough had such an agreement until recently

Access to Information

Consequence of Information Access

- Industry acts to prevent the best information from harming its position on taxes
 - Low flow documents
 - Royalty trust statements removed
 - BP Pipelines no longer participating in reserves function [2007-2009 Trial Tr. 11480]
 - As a matter of policy DOR does not compel the production of useful information
- DOR does not make publicly available taxpayer information in its possession
- Result–DOR and Legislature do not have access to information necessary to be informed about oil and gas tax issues in Alaska

Access to Information Source Materials

- Alaska Statutes

Conclusion

- Open Access to Facilities
- Reasonable Transportation Rates
- Minimize Barriers to Entry
- Sound Tax Policy
 - Recognizes Market Structure
 - Recognizes Specific Behavior and Participants Most Likely to Be Impacted by Tax Incentives
 - Recognizes Stage of Development of Basin

THANK YOU

16.

Gleason Decision

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

THIRD JUDICIAL DISTRICT AT ANCHORAGE

BP PIPELINES (ALASKA) INC.,)
EXXONMOBIL PIPELINE COMPANY,)
UNOCAL PIPELINE COMPANY,)
CONOCOPHILLIPS TRANSPORTATION)
ALASKA, INC. and KOCH ALASKA)
PIPELINE COMPANY, Owners, and)
ALYESKA PIPELINE SERVICE COMPANY,)
as Agent for the Owners,)

FAIRBANKS NORTH STAR BOROUGH and)
CITY OF VALDEZ,)

Appellants/Cross-Appellants,)

v.)

STATE OF ALASKA DEPARTMENT OF)
REVENUE, STATE ASSESSMENT)
REVIEW BOARD, and NORTH SLOPE)
BOROUGH,)

Appellees.)

RECEIVED
DEC 30 2011

Case No. 3AN-06-08446 CI
(Consolidated)
2007/08/09 Tax Years

DECISION FOLLOWING TRIAL DE NOVO

**2007, 2008, and 2009 Assessed Valuations
of the Trans Alaska Pipeline System**

TABLE OF CONTENTS

I. PROCEDURAL BACKGROUND.....1

II. LEGAL STANDARDS7

 A. Taxation Authority7

 B. Standard of Review and Burden of Proof9

 C. History of Ad Valorem Tax Assessments of TAPS11

III. DESCRIPTION OF THE PROPERTY19

 A. Ownership19

 B. Physical Description20

 C. Original Construction and Strategic Reconfiguration20

 D. Limited-Market Property23

 E. Special-Purpose Property.....23

 F. Integrated Economics.....23

 G. Unique Regulatory Status.....26

IV. PREMISE OF VALUE.....27

**V. THE OWNERS’ MAINTENANCE OF TAPS’ CAPACITY OF 1.1 MILLION BBL/D
WITH UPWARD SCALABILITY TO 2.1 MILLION BBL/D.....43**

VI. CHOICE OF VALUATION METHOD49

VII. THE COST APPROACH53

 A. Replacement Cost New54

 1. A Summary of the Cost Studies55

 2. The Stantec Hypothetical Pipeline Is Not an Acceptable Comparison Property
 to TAPS for Ad Valorem Tax Purposes59

 a. Legal Restrictions61

 b. The Stantec Design Is Not of Similar Quality and Like Utility63

 c. Appraisal Theory73

 d. The Stantec Design Is Unproven and Unknown.....76

 e. The Stantec Design Does Not Capture All Costs80

f. The Stantec Design Does Not Permit Adequate Quantification of Obsolescence	81
3. The Pro Plus RCN	83
a. The Pro Plus Experts	83
b. The Pro Plus Design	83
c. The Pro Plus Cost Estimate	86
i. Direct Costs	86
ii. Indirect Costs, Including Contingency	107
4. Conclusion of the RCN of TAPS	121
B. Depreciation	123
1. Methods of Calculating Depreciation	123
2. Life of the Line	132
a. Minimum Throughput Capacity	132
b. Proven Reserves	150
i. The Definition of Proven Reserves	150
ii. The Municipalities' Production Forecasts and Reserves Estimates Generally Provide a Reliable Basis for Determining TAPS' Estimated Proven Reserves	160
iii. The Forecasts and Reserves Estimates Offered by the Owners' Witnesses were not Persuasive	165
iv. The Department's Production Forecasts and Reserves Estimates Are Unreliable	170
v. Conclusions on the Proven Reserves	172
3. Application of the Economic Age-Life Method	175
a. TAPS' Effective Age	175
b. Additional Functional Obsolescence	177
c. Additional Economic Obsolescence	181
i. Scaling	181
ii. No Additional Economic Obsolescence Adjustment Is Warranted	184
C. RCNLD Conclusion of Value	190
VIII. THE INCOME APPROACH	191
A. The Integrated Income Approach to the Valuation of TAPS	191
B. The Tariff Income Approach Does Not Capture the Full and True Value of TAPS Under AS 43.56.060(e)(2)	194
C. Tariff Income Is Not a Reliable Indicator of Economic Value	198
IX. THE COMPARABLE SALES APPROACH	205
X. RECONCILIATION AND CONCLUSION	211

I. PROCEDURAL BACKGROUND

1. This is a consolidated appeal of the State Assessment Review Board (“SARB” or “Board”) Decisions of the 2007, 2008, and 2009 assessments of the Trans Alaska Pipeline System (“TAPS”) for ad valorem tax purposes under AS 43.56. SARB assessed the value of TAPS for 2007 at \$4.588895312 billion, for 2008 at \$6.154447972 billion, and for 2009 at \$9.045892 billion.¹

2. SARB’s 2006 assessment of TAPS was also appealed to this Court. After a de novo trial of over five weeks in 2009, this Court issued an Amended Decision Upon Reconsideration Following Trial De Novo on October 26, 2010, (“Amended Decision”) with respect to that tax year, which concluded that the assessed value of TAPS for 2006 was \$9.977 billion. That decision is currently on appeal to the Alaska Supreme Court.

3. The appeal to this Court of the 2007 through 2009 tax years culminated in a non-jury trial that began on September 6, 2011 and lasted approximately nine weeks.² Thousands of pages of exhibits and extensive deposition testimony were admitted into the record, together with the trial testimony of the parties’ many witnesses. The administrative record for each of the SARB proceedings in 2007 through 2009 was also submitted to the Court.³ And the parties have each filed extensive proposed Findings of Fact and Conclusions of Law that altogether total approximately 900 pages. Based on all the

¹ The three SARB decisions can be found in the trial exhibits at MUN7-0234 (2007), MUN7-0235 (2008) and MUN7-0236 (2009).

² See AS 43.56.130(i).

³ Pursuant to the Court’s Order Re Motion to File Expert Reports and Admit the SARB Record (July 26, 2011) at 6, the SARB record and hearing transcript for each of these years was admitted into the court record. See also Appellate Rule 609(b)(2).

evidence in the record, the arguments of counsel, the parties' proposed findings, and upon consideration of the applicable law, this Court is now entering the following Findings of Fact and Conclusions of Law.⁴

4. AS 43.56.010 *et seq.* are the statutes governing the ad valorem taxation of oil and gas property in Alaska. The statute provides for such property to be centrally assessed each year by the Tax Division ("Division") within the Department of Revenue ("Department"), based on a lien date of January 1. Taxpayers and affected local governments have the right to appeal the Division's assessed valuation to SARB, which is created within the Department. These parties then have a right to appeal from SARB to the Superior Court in the form of a trial de novo pursuant to AS 43.56.130. The TAPS Owners,⁵ the Fairbanks North Star Borough, and the City of Valdez appealed SARB's 2007 decision to this Court. These parties, as well as the North Slope Borough, appealed SARB's 2008 and 2009 decisions to this Court. The three years were consolidated for purposes of trial. The Department and SARB are appellees in each of the three appeals.⁶ The Municipalities have asserted to this Court that TAPS' assessed value should be \$13.689 billion for 2007, \$14.804 billion for 2008, and \$14.422 billion for 2009.⁷ The Owners have asserted that TAPS' assessed value should be \$1.1 billion for 2007, \$1.2 billion for 2008, and \$1.3 billion

⁴ This Court is cognizant of Civil Rule 52(a)'s specification that the Court "shall find the facts specifically and state separately its conclusions of law thereon." But for ease of comprehension of a decision with this number of issues and level of complexity, this Court has not segregated the conclusions of law, but instead notes that instances in which this Court is interpreting the law, as opposed to making factual findings, should be clear from the context of this decision. See Civil Rules 92, 94.

⁵ The Owners of TAPS are BP Pipelines (Alaska) Inc., ConocoPhillips Transportation Alaska, Inc., ExxonMobil Pipeline Company, Koch Alaska Pipeline Company, and Unocal Pipeline Company (hereinafter "Owners").

⁶ AS 43.56.040.

⁷ Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 893.

for 2009.⁸ The Department did not present an opinion of value for TAPS at the trial de novo for the three tax years at issue.⁹

5. AS 43.56.080 grants the Division certain investigative powers when assessing AS 43.56 properties, including the power to “enter any premise necessary for the investigation during reasonable hours,” to “examine property and appropriate records,” and to compel owner representatives “to appear for examination under oath by the department.”¹⁰ There was no persuasive evidence presented at the trial de novo that the Division has ever exercised these powers with respect to the valuation of TAPS.¹¹

6. The Division broadly interprets what it considers “taxpayer confidential” information under applicable statutes and will not disclose such information to the Municipalities specifically or to the public generally.¹² The Division considers all information that it receives from a taxpayer as “taxpayer confidential,” even if it does not contain the particularities of a taxpayer’s business affairs and is obtainable from the public domain.¹³ As a result, the Division did not provide the Owners’ new replacement cost study by Stantec Consulting, Inc. (“Stantec”) to the Municipalities.

⁸ TO-07-0004.0138.

⁹ The Department indicated that it did not render opinions of value at the trial de novo because in doing so it would be rendering a supplemental assessment for each of the years in question, which, in turn would trigger a new round of administrative action and appeals for each tax year rather than a single and definitive presentation in a de novo context before the court.

Department’s Proposed Findings of Fact and Conclusions of Law ¶ 6.

¹⁰ AS 43.56.080.

¹¹ See Greeley Dep. at 209 (June 6, 2011).

¹² See AS 40.25.100(a); AS 43.05.230(a).

¹³ Tr. 10875-77 (Bales).

7. AS 43.56.060(g) provides that “[t]he department may enter into agreements with a municipality for the cooperative or joint administration of the assessing authority conferred on the department by this section.”¹⁴ The North Slope Borough previously had such an agreement with the Department. The City of Valdez and Fairbanks North Star Borough have never been parties to joint assessment agreements with the Department.¹⁵

8. In its 2010 decision, SARB expressed its concerns regarding the Division’s assessment practices:

The Board believes that it is time for the Division to address the problems created by the way it handles taxpayer confidential information in the assessment process. The Division's failure to provide interested parties with the information on which the assessment was made in time to allow those parties meaningful input in the determination of the property's assessed value, before that determination is subject to limited review of an appeal before the Board, has the potential to throw the fundamental fairness of the AS 43.56 assessment process into question. The Board believes that, due to the Division's current practices with regard to the use of taxpayer confidential information in its AS 43.56 assessments, that process is close to broken and is headed in the wrong direction.¹⁶

This Court concurs with the Board’s observations in this regard.

9. The procedural inadequacies at the agency level have by and large been remedied on appeal to this Court due to the applicability of the civil discovery rules, albeit at considerable expense and delay.

10. This Court interprets the phrase “proved at the hearing” of subsection (f) of AS 43.56.130 to permit a party to introduce new evidence at the trial de novo. As a result, while

¹⁴ AS 43.56.060(g).

¹⁵ 2007 SARB Tr. 0137-0138 (Greeley).

¹⁶ MUN7-0237 at 39.

the SARB hearings have each lasted a few days, the consolidated trial de novo before this Court for the 2007 through 2009 tax years' assessments lasted approximately nine weeks.

11. Nearly all the witnesses at the trial testified as experts or as hybrid fact and expert witnesses, and extensive expert reports were prepared. Their qualifications were set out in detail in their testimony and are not restated in this decision. In the 2006 tax year litigation, expert reports for all of the parties were admitted into evidence by stipulation of the parties. For the three tax years now at issue, the Owners maintained a hearsay objection to the admission of most of the expert reports, including most of the reports prepared by their own experts. In a July 26, 2011 "Order re Motion to File Expert Reports and Admit the SARB Record," this Court stated that Evidence Rule 803(23) could be an applicable exception to the hearsay rule for these reports in this proceeding. Over the objection of the Municipalities and the Department, the Owners were permitted to maintain their objection to the admission of most of the expert reports under Rule 803(23), including their own experts reports, while nonetheless seeking admission of their own reports.¹⁷ During and after trial, most of the expert reports were admitted into the record.¹⁸ However, given the extensive dispute between the parties with respect to most of the expert reports, this Court has minimized its consideration of those reports. Any expert report that was admitted over objection of any party has not been relied upon or considered by this Court in determining

¹⁷ See Order re Expert Reports (Oct. 24, 2011).

¹⁸ See Order Re Owners' Motion to Admit Exhibits (Nov. 29, 2011).

the assessed value of TAPS for the three years in question, excepting only those specific pages of reports identified in this decision.¹⁹

12. The proceedings surrounding these three tax years have been considerably more contentious than those held with respect to the 2006 tax year. Several hundred pretrial motions were filed and determined. This Court issued an Order Re Department of Revenue's Motion for Preclusion of Issues and Municipalities' Motion to Bar Relitigation on August 8, 2011 ("Collateral Estoppel Order"). That Order would have applied the doctrine of collateral estoppel so as to preclude the relitigation of many of the determinations reached by this Court in the 2006 tax year proceeding to the current tax years, while preserving each party's right to seek to introduce newly discovered evidence "that purports to demonstrate changed facts such that application of collateral estoppel would not be warranted."²⁰ However, for reasons that this Court strived to fully explain on record at trial on September 13 and 19, 2011, that Order was vacated and the trial de novo then proceeded with respect to all pending issues.²¹

13. The length of the trial proceeding was not primarily due to the fact that three years were heard at one time. Indeed, very little trial time was spent focusing on the differences between the three lien years. Rather, the evidence focused on each of the substantive issues applicable to all three tax years. Each of the parties presented a considerably more technical and in-depth analysis of many of the issues identified in the 2006 tax year proceeding.

¹⁹ There have been multiple occasions in recent months that this Court has reviewed expert reports for other purposes, such as to determine whether a motion to preclude testimony should be granted, or whether certain trial testimony fell within the scope of opinions discussed in the report. See Evidence Rule 104.

²⁰ Collateral Estoppel Order at 4.

²¹ Tr. 2906-08 (Court).

14. Pursuant to this Court's August 25, 2011 Order Re Remaining Pretrial Issues and Amended Order Of Presentation, this Court heard testimony and evidence from each of the parties by topic area presented in the following order:

- a. Appraisal Theory
- b. Replacement Cost New (including contingency)
- c. Economic/Regulatory/Contractual Issues
- d. Mechanical Capacity – both upper and lower
- e. Reserves/North Slope Production Forecasts
- f. Appraisal/Valuation of TAPS

II. LEGAL STANDARDS

A. Taxation Authority

15. “The Alaska Constitution empowers the legislature to prescribe valuation standards.”²² “The legislature chose to define those standards broadly, requiring that property be assessed ‘at its full and true value.’”²³

16. AS 43.56.010 *et seq.* became law in 1973. These statutes provide that property used for oil and gas exploration, production, and pipeline transportation would not be valued for assessment purposes by municipalities under AS 29.45; instead these types of properties would each be uniformly and centrally assessed by the State.²⁴

17. AS 29.45.080(b) provides that “[a] municipality may levy and collect a tax on the full and true value of taxable property taxable under AS 43.56 as valued by the Department of Revenue”

²² *Fairbanks N. Star Borough Assessor's Office v. Golden Heart Utils., Inc.*, 13 P.3d 263, 267-68 (Alaska 2000). See also Alaska Const., art. IX, § 3.

²³ *Golden Heart Utils.*, 13 P.3d at 267-68.

²⁴ *Minutes* at 50, 54, H. Fin. Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973); *Minutes* at 76, H. Fin. Comm., 8th Leg., 1st Spec. Sess. (Oct. 24, 1973); S.J. at 81-82, 8th Leg., 1st Spec. Sess. (Nov. 3, 1973); Amended Decision ¶ 15.

18. AS 43.56.060(e)(2) provides in relevant part:

The full and true value of taxable property used or committed by contract or other agreement for pipeline transportation of gas or unrefined oil or in the operation or maintenance of facilities for the pipeline transportation of gas or unrefined oil is: . . .

(2) determined on each January 1 thereafter with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically, and legally deliverable into the transportation facility[.]

19. The Department of Revenue's implementing regulation for the statute provides:

[T]he full and true value of pipeline property in operation is its economic value based upon the estimated life of proven reserves of the gas or oil then technically, economically and legally deliverable into the transportation facility. Economic value is determined by the use of standard appraisal methods such as replacement cost less depreciation, capitalization of estimated future net income, analysis of sales, or other acceptable methods. The valuation may include any item contributing to value including capitalized interest.²⁵

This regulation has been in place since 1975 and in this precise form since 1982.

20. The implementing regulation differs slightly from the statute, as the regulation provides that "the full and true value of pipeline property in operation *is* its economic value based on the estimated life of proven reserves ..." (Emphasis added). If a statute and a regulation conflict, the provisions of the statute control.²⁶

21. Each year, as part of the ad valorem assessment process, the property owners file a rendition with the Department identifying all taxable property.²⁷ There has been no

²⁵ 15 AAC 56.110(c)

²⁶ *State v. Kenaitze Indian Tribe*, 83 P.3d 1060, 1064-1065 (Alaska 2004).

²⁷ The renditions filed by the TAPS Owners for each of the applicable years can be found in the SARB record as follows: 2007 R. 001076 – 1087; 2008 R. 003989 – 4036; 2009 R. 003528 – 3618.

claim or appeal point raised that the property identified in the TAPS Owners' renditions is not taxable under AS 43.56.060(e)(2). Nor does this Court find that there is any escaped property.²⁸ Accordingly, this Court finds that all property included in the 2007, 2008, and 2009 Owners' renditions is taxable under AS 43.56.060(e)(2).

B. Standard of Review and Burden of Proof

22. This Court has previously determined in the 2006 tax year proceeding, and again holds, that the appellants bear the burden of proof to demonstrate by a preponderance of the evidence that an adjustment from SARB's assessed value is warranted pursuant to the standard in AS 43.56.130(f): "The only grounds for adjustment of assessed value is proof of unequal, excessive, or improper valuation or valuation not determined in accordance with the standards set out in this chapter."²⁹

23. This Court will accord deference to SARB's interpretation of the statutory premise of value established by the Legislature in AS 43.56.060(e)(2) because the legal interpretation of that statute "implicates agency expertise or the determination of fundamental policies within the scope of the agency's statutory functions."³⁰ The Board, in

²⁸ Tr. 13063 (Greeley).

²⁹ See Amended Decision ¶ 20. In addition, a party could present a constitutional challenge to an administrative determination. *Id.* ¶ 20 n.9.

³⁰ See *Bullock v. State, Dept. of Comm. Affairs*, 19 P.3d 1209, 1213-14 (Alaska 2001) (applying "highly deferential" reasonable basis standard of review to the Department of Revenue's statutory interpretation regarding AS 43.56 property). See also *Storrs v. State Med. Bd.*, 664 P.2d 547, 552 (Alaska 1983) *cert. denied*, 464 U.S. 937 ("Statutory construction adopted by those responsible for administering a statute should not be overruled in the absence of 'weighty reasons.'"). In contrast, if the interpretation of a statute does not involve agency expertise, such that the "agency's specialized knowledge and experience would not be particularly probative as to the meaning of the statute," then this Court is to interpret the statute under the substitution of judgment standard, and "adopt the rule of law that is most persuasive in light of precedent, reason, and policy." *Williams v. Abood*, 53 P.3d 134, 139 (Alaska 2002). See also Sutherland § 66.4 at 48 (3rd ed. 2003) ("One of the most significant aids of construction in determining the meaning of revenue laws is the administrative interpretation given such acts by the agency that is responsible for its administration and enforcement.").

turn, has accorded deference to the Division in this regard. And yet this Court is cognizant that the volunteer Board had only a few days of testimony each year to consider the value of TAPS, whereas this Court had nine weeks of trial together with extensive pretrial motion practice. But having studied each of SARB's decisions for the three applicable tax years and the preceding years, this Court has found the Board's analysis, and particularly its discussion of appraisal theory, to be quite helpful in determining the assessed value of TAPS.

24. The Alaska Supreme Court has accorded broad discretion to taxing authorities in determining the valuation method.³¹ The appellants must prove that the selected method was based on a fundamentally wrong principle of valuation.³²

25. As to the application of appraisal methodology and all other issues that were not before the Board, this Court has engaged in original fact finding, and applied a preponderance of the evidence standard to determine whether SARB's assessed values resulted in unequal, excessive, or improper valuations.

26. In evaluating the evidence, the Court has considered Civil Pattern Jury Instruction 02.23:

The evidence should be evaluated not only by its own intrinsic weight but also according to the evidence which is in the power of one party to produce and of the other party to contradict. If weaker and less satisfactory evidence is offered when it appears that stronger and

³¹ See *Marathon Oil Co. v. Dep't of Natural Res.*, 254 P.3d 1078, 1082 (Alaska 2011); *Horan v. Kenai Peninsula Borough Bd. of Equalization*, 247 P.3d 990, 998 (Alaska 2011); *Fairbanks N. Star Borough Assessor's Office v. Golden Heart Utils.*, 13 P.3d 263, 268 (Alaska 2000); *Cool Homes, Inc. v. Fairbanks N. Star Borough*, 860 P.2d 1248, 19262 (Alaska 1993); *N. Star Alaska Hous. Corp. v. Fairbanks Borough Bd. of Equalization*, 778 P.2d 1140, 1143-44 (Alaska 1989); *Twentieth Century Inv. v. City of Juneau*, 359 P.2d 783, 788 (Alaska 1961).

³² See *N. Star Hous. Corp.*, 778 P.2d at 1144 n. 6.

more satisfactory evidence was within the power of one party to produce, the evidence should be viewed with caution.

C. History of Ad Valorem Tax Assessments of TAPS

27. SARB is a five-member board created within the Department. Its sole purpose is hearing appeals from assessed value determinations made by the Division under AS 43.56.³³ Each member of SARB is appointed by the Governor, confirmed by the Legislature, and must be knowledgeable of assessment procedures.³⁴ In its 2007 TAPS determination, SARB stated it “is designed to provide a balanced expert review of oil and gas production property valuation issues.”³⁵

28. Prior to 2001, there were no administrative or court proceedings addressing the value of TAPS. Instead, the Division prepared a valuation based on consideration of both the income and cost approaches, with the income approach the more dominant in the analysis. Then the Division would meet with the Owners, typically in an out-of-state hotel conference room, and TAPS’ assessed valuation would be determined in a negotiated settlement reached between the Division and the TAPS Owners with little, if any, participation by the Municipalities.³⁶

29. In 2001, the Division valued TAPS at \$2.75 billion. Both the Owners and the Municipalities appealed that determination to SARB. There, each party “relied most heavily

³³ AS 43.56.040.

³⁴ AS 43.56.040.

³⁵ MUN7-0234 at 21.

³⁶ MUN7-0234 at 4; Tr. 12419-12420 (Hoffbeck).

on projected TAPS tariff income data in setting their valuation estimates.”³⁷ SARB stated in its 2009 Certificate of Determination:

Because there had never been a replacement cost study for the TAPS, the 2001 cost value estimates had to be calculated based on the original cost of the TAPS. Having to adjust these original costs forward so many years made the valuations based on the original costs a very poor indicator of the 2001 value of the TAPS.³⁸

30. In 2001, SARB concluded, based upon the evidence then available, that the Division’s assessed value of \$2.75 billion should be increased to \$3.017 billion.³⁹

31. From 2002 through 2004, the assessed valuation of TAPS remained at \$3.017 billion as the result of negotiated agreements between the Division, the Owners and the Municipalities.⁴⁰

32. In 2005, the Division set a \$3 billion assessed valuation for TAPS.⁴¹ In so doing, the Division relied primarily on the Replacement Cost New Less Depreciation (“RCNLD”) approach because it had received updated replacement cost study information from both the Owners and the Municipalities.⁴² In addition, “uncertainty about future tariff rates in 2005 led the Division to question whether the income approach using a capitalized estimated future tariff income stream still provided the most complete and reliable estimate of the value of TAPS.”⁴³

³⁷ MUN7-0234 at 4.

³⁸ MUN7-0236 at 6.

³⁹ MUN7-0236 at 7.

⁴⁰ MUN7-0236 at 7.

⁴¹ MUN7-0234 at 8.

⁴² MUN7-0234 at 8.

⁴³ MUN7-0234 at 8.

33. Both the Owners and the Municipalities appealed the Assessor's 2005 determination to SARB.⁴⁴ After a three-day hearing, the Board agreed with the Division that the value of TAPS could not be accurately measured by the tariff income approach because the uncertainty of future tariff rates and other factors caused the value of future tariff income streams to understate the full and true value of TAPS.⁴⁵ SARB also concluded that neither the Owners nor the Municipalities had proven that the Division's \$3 billion assessed value was "unequal, excessive, improper or otherwise contrary to the standards set out in AS 43.56," even though the Board found that it was "at the low end of an acceptable value range."⁴⁶

34. Both the Owners and the Municipalities appealed the 2005 SARB Decision to the Superior Court. However, by stipulation of the parties, the appeals were dismissed.

35. In 2006, the Division relied on the same basic data and RCNLD methodology as it had in 2005, and determined that the assessed value of TAPS was \$3.641 billion.⁴⁷

36. The parties appealed the Division's 2006 assessment to SARB.⁴⁸

37. SARB adjusted the 2006 assessed value from \$3.641 billion to \$4.3062718 billion.⁴⁹ The Owners, as well as the Fairbanks North Star Borough and City of Valdez, appealed to this Court. A five week trial de novo was held in the fall of 2009. Thereafter, this Court issued a 170-page decision in 2010 that relied on the cost approach to valuation

⁴⁴ MUN7-0232 at 8.

⁴⁵ MUN7-0234 at 9.

⁴⁶ MUN7-0234 at 9.

⁴⁷ MUN7-0234 at 9.

⁴⁸ MUN7-0234 at 10.

⁴⁹ MUN7-0234 at 10.

and set the assessed value of TAPS for 2006 at \$9.977 billion.⁵⁰ That Decision is presently on appeal to the Alaska Supreme Court.⁵¹

38. In 2007, the Division determined TAPS' assessed value was \$4.578 billion.⁵² Both the Owners and the Municipalities appealed to SARB. After a hearing, SARB concluded that the 2007 assessed value of TAPS was \$4.588895312 billion.⁵³

39. In its 2007 Decision, SARB held that the term "economic value" in AS 43.56.060(e)(2) "means more than the value obtained using a simple willing buyer, willing seller, open market model."⁵⁴ SARB reasoned:

Often there is no open market for oil and gas transportation pipelines in production as stand alone properties. Often there is no willing buyer or a willing seller for an Alaska pipeline at [a] price that would reflect the pipeline's value. Attempts to create a model based on a willing buyer and willing seller may overstate or understate the value of such a pipeline because its value is often more closely tied to the economic life of [the] oil field it serves than its value in a theoretical open market without reference to the oil fields it serves. Hence Alaska Statute 43.56.060(e)(2) requires an assessed valuation based on the pipeline's economic value with due consideration given to the reserves the pipeline serves in estimating that economic value.⁵⁵

40. In its 2007 Decision, SARB critiqued "the Division's frequent use of the term conservative in reference to some of its assumptions and estimates."⁵⁶ The Board added that "the object of an assessor valuing property under Alaska Statute 43.56.060(e)(2), is to make the best estimate of value, that is, to determine the pipeline's most likely value based

⁵⁰ Amended Decision ¶ 511.

⁵¹ S-14095; S-14116.

⁵² MUN7-0234 at 2.

⁵³ MUN7-0234 at 24.

⁵⁴ MUN7-0234 at 14.

⁵⁵ MUN7-0234 at 14. *See also* Amended Decision ¶ 53.

⁵⁶ MUN7-0234 at 20. *See also* Amended Decision ¶ 53.

on the available evidence, not to make a conservative estimate of value, or the lowest estimate of value within an acceptable range of possible values.”⁵⁷

41. In 2008, the Division determined that the assessed value of TAPS was \$7.16589746 billion.⁵⁸ The parties appealed to SARB. There, the Owners asserted that TAPS’ assessed value should be \$800 million; the Municipalities argued that TAPS’ assessed value should be set no lower than \$12 billion.⁵⁹ SARB agreed with the Division that “the Pro Plus cost study [advanced by the Municipalities] was generally more detailed and more reliable than the current and previous Mustang cost study.”⁶⁰ However, SARB did not accept the Pro Plus contingency estimate of 25%.⁶¹ The Board concluded that the increased reliability of the Pro Plus study should have resulted in the contingency going down, not up, and it therefore set the contingency at 5%.⁶²

42. After adjusting the contingency percentage, SARB concluded that the assessed value of TAPS in 2008 was \$6.15447972 billion.⁶³ SARB commented that an assessed value may increase from year to year due to the availability of more reliable data, “even if the actual value of the property did not change.”⁶⁴

43. By 2009, the Municipalities and the Department had received significant materials through the discovery process in the 2006 case before this Court.

⁵⁷ MUN7-0234 at 20. See also Amended Decision ¶ 55.

⁵⁸ MUN7-0235 at 26.

⁵⁹ MUN7-0235 at 2.

⁶⁰ MUN7-0234 at 19.

⁶¹ MUN7-0235 at 19-20.

⁶² MUN7-0235 at 19-20.

⁶³ MUN7-0235 at 26.

⁶⁴ MUN7-0235 at 25.

44. In 2009, the Division accepted and relied upon the Municipalities' Pro Plus study but reduced the contingency from 25% to 10% and the owners' costs from 10% to 5%, and valued the property at \$7.71506816 billion.⁶⁵ Both the Owners and the Municipalities appealed to SARB.

45. Before SARB in 2009, the Owners asserted that TAPS' value was less than \$1 billion; the Municipalities argued that TAPS' assessed valuation should be set no lower than \$12 billion.⁶⁶ SARB found that the Pro Plus witnesses had provided full support for a 25% contingency and owners' costs of 10%.⁶⁷ Accordingly, SARB adjusted the Division's value for these two items to result in an assessed valuation of \$9.0458952 billion.⁶⁸

46. In each of the 2007 through 2009 assessments of TAPS, both the Division and SARB concluded that:

- a. after due consideration of the income and sales approaches, the cost approach was most applicable to value TAPS;
- b. TAPS was a special use or special purpose property; and
- c. the assessed value was based on the best cost studies then available to the Division and SARB, which in 2007 was comprised of a trended version of an older Mustang cost report, in 2008 was comprised of a Pro Plus pipeline replacement cost based on a cost-estimated "Spread 6" and factored for Spreads 1-5, combined with a Mustang Valdez marine terminal ("VMT")

⁶⁵ MUN7-0236 at 2.

⁶⁶ MUN7-0236 at 2.

⁶⁷ MUN7-0236 at 17, 19.

⁶⁸ MUN7-0236 at 18.

replacement cost estimate, and in 2009 was comprised of a full Pro Plus pipeline and VMT cost estimate.⁶⁹

47. In 2010, the Division valued TAPS at \$9.20346143 billion.⁷⁰ The Owners presented a new cost study prepared by Stantec.⁷¹ At the ensuing 2010 SARB hearing, the Owners asserted that TAPS was worth no more than \$1.4 billion. The Municipalities asserted that TAPS' assessed valuation should be set at \$11.8 billion.⁷² The Board adjusted the Assessor's calculation of ad valorem taxes during construction and the economic end-of-life for TAPS, with a resultant valuation of \$9,638,669,398.⁷³ That determination is presently on appeal to this Court, but a trial date has not yet been scheduled.

48. In 2011, the Division valued TAPS at \$7.9329798 billion.⁷⁴ The Owners and Municipalities appealed that valuation to SARB. The Board found that the Division's valuation was improper because it failed to give this Court's decision in the 2006 TAPS appeal proper weight in making an economic end-of-life calculation.⁷⁵ After making this adjustment to the Division's valuation, the Board determined that the 2011 assessed valuation of TAPS was \$8,671,720,679.⁷⁶ That determination is also on appeal to this Court.

⁶⁹ Tr. 6758-52 (Greeley).

⁷⁰ MUN7-0237 at 1.

⁷¹ MUN7-0237 at 19.

⁷² MUN7-0237 at 2.

⁷³ MUN7-0237 at 42.

⁷⁴ MUN7-0238 at 2.

⁷⁵ MUN7-0238 at 19.

⁷⁶ MUN7-0238 at 34.

49. The Board's Certificates of Determination for 2010 and 2011 reflect careful consideration of this Court's rulings from the 2006 tax year to the years at issue before the Board, thereby according some degree of predictability of outcome in this complex and highly contentious process. However, this Court has not accorded weight to the Board's findings regarding the assessed value of TAPS in those subsequent years given the Owners' observation that to do so creates a degree of circularity that could impact the nature of this trial de novo for the 2007 through 2009 tax years.

50. James Greeley became the State Petroleum Property Assessor in 2007. No disparity or inequality in valuation methodology among AS 43.56 pipelines has been demonstrated during the lien years. There is no basis in the record to support a claim that the 2007, 2008, or 2009 TAPS assessment violates the equal protection clause under either the state or federal Constitution, or is otherwise impermissibly discriminatory.

51. The Court found in the 2006 tax year proceedings that the Department did not abruptly and without notice change its policy to consider the cost approach for the first time in 2005.⁷⁷ This Court again so finds with respect to the 2007 through 2009 tax years.

52. The Department's use of the cost approach does not constitute a "de facto regulation." The applicable regulation has expressly permitted reliance on a cost approach for over three decades.⁷⁸

53. The record does not support a claim that the 2007, 2008, or 2009 assessment violates the due process clause of either the state or federal Constitution.

⁷⁷ See Amended Decision ¶ 63.

⁷⁸ 15 AAC 56.110(c).

III. DESCRIPTION OF THE PROPERTY

A. Ownership

54. As of January 1 for each of the three tax years at issue, TAPS was owned by BP Pipelines (Alaska) Inc. (46.9%), ConocoPhillips Transportation Alaska, Inc. (28.3%), ExxonMobil Pipeline Company (20.3%), Koch Alaska Pipeline Company (3.1%), and Unocal Pipeline Company (1.4%).⁷⁹ Alyeska Pipeline Service Company ("Alyeska") is the operating agent for the Owners.⁸⁰

55. TAPS is physically a single pipeline, but there are effectively five different pipelines because each TAPS Owner has an undivided ownership interest in TAPS. This ownership structure permits each individual Owner to use its portion of TAPS as part of the vertically integrated business operations of that Owner's affiliates. Each TAPS Owner maintains a separate tariff and each accepts nominations to its undivided ownership interest.⁸¹

56. Each Owner's entitlement to a portion of the pipeline's capacity or "space" is established under the Amended Capacity Settlement Agreement ("ACSA"), which together with the TAPS Operating Agreement provides that each Owner's share of pipeline capacity is equal to the pipeline ownership percentage multiplied by TAPS' capacity, which for each of the lien years was 1.1 million bbl/d.⁸²

⁷⁹ MUN7-0001 at 485; MUN7-0800 at 15.

⁸⁰ MUN7-0001 at 485; MUN7-0800 at 15.

⁸¹ MUN7-0001 at 977 (Coulson); Tr. 8357-58, 8550 (Cicchetti).

⁸² MUN7-0001 at 982-83 (Coulson).

B. Physical Description

57. TAPS is an 800-mile long, 48-inch diameter crude oil pipeline system that crosses three mountain ranges and over 800 rivers and streams during its traverse from the Alaska North Slope ("ANS") oil fields to the Valdez Marine Terminal ("VMT").⁸³ TAPS consists of the right-of-way, pipe, pumps, tanks, tanker loading facilities and associated equipment.⁸⁴ Approximately 420 miles of the 800-mile pipeline are aboveground and supported by 39,000 pairs of Vertical Support Members ("VSMs").⁸⁵ TAPS is the only pipeline transporting crude oil from the ANS, and is therefore a basin-opening transportation system. As of each lien date, there was no other viable transportation alternative to carry significant quantities of oil from the ANS to market.⁸⁶

58. TAPS' taxable property includes only the tangible real and personal property from Pump Station 1 through the VMT and does not include intangible property, marine tankers, refineries, ANS proven reserves, ANS crude oil, ANS exploration property, or any property that is upstream of Pump Station 1.⁸⁷

C. Original Construction and Strategic Reconfiguration

59. Construction of TAPS began in 1974 and was completed in the summer of 1977. It required 515 federal permits and 832 state permits.⁸⁸ There were 14 airfields of varying lengths built to support the construction of TAPS.⁸⁹ The construction workforce

⁸³ MUN7-0001 at 965 (Coulson).

⁸⁴ Tr. 11751-11752 (Remsha).

⁸⁵ MUN7-0001 at 520, 547, 549.

⁸⁶ Tr. 8916 (Cicchetti); MUN7-01 at 3767 (Coulson).

⁸⁷ Tr. 529 (Remsha); Tr. 12903 (Greeley).

⁸⁸ MUN7-0001 at 502.

⁸⁹ MUN7-0001 at 484.

totaled approximately 70,000 employees, with a peak number of 28,000 employees working in October 1975.⁹⁰ At the time of its construction, TAPS was the largest privately funded construction project in U.S. history.⁹¹ Before construction began, the estimated cost was set at \$863 million. However, when finally completed in 1977, the final cost of TAPS was nearly ten times greater, at approximately \$8 billion.⁹²

60. The initial design capacity for TAPS in August 1970 was 600,000 barrels per day (“bbl/d”) of throughput.⁹³ In July 1974, the design capacity was increased to 1.2 million bbl/d.⁹⁴ And soon after it was again adjusted to 1.42 million bbl/d.⁹⁵

61. “Pursuant to an agreement among the TAPS carriers dated March 29, 1979, the Owners have utilized a chemical drag reduction known as ‘DRA’ to increase throughput in excess of TAPS’ 1.42 million [bbl/d] design capacity.”⁹⁶

62. After the use of DRA was implemented, TAPS was able to transport 2.1 million bbl/d at its peak production in 1988. After peaking in the late 1980s, throughput on TAPS has gradually reduced. As of the January 1, 2007, 2008, and 2009 lien dates, the Department of Revenue estimated production of ANS crude oil and natural gas liquids (“NGLs”) at 740,000 bbl/d for fiscal year 2007, at 731,000 bbl/d for fiscal year 2008, and at 691,000 bbl/d for fiscal year 2009.⁹⁷

⁹⁰ MUN7-0001 at 489.

⁹¹ MUN7-0001 at 965 (Coulson).

⁹² MUN7-0001 at 488.

⁹³ MUN7-0215 at 11. *See also* Tr. 7058 (Ray).

⁹⁴ MUN7-0215 at 62.

⁹⁵ TO-07-0179.0130. *See also* MUN7-0001 at 2026.

⁹⁶ TO-07-0190.0001 (FERC Order Approving Agreement, issued May 15, 1998).

⁹⁷ MUN7-0018 at 13, 20, 27. *Cf.* TO-07-0004 at 78, 111, 126.

63. The first oil began to flow through TAPS on June 20, 1977. The first tanker of crude oil left the VMT on August 1, 1977. At that time, ANS proven reserves were estimated at approximately 9.6 billion barrels. As of January 1, 2007, over 15 billion barrels of oil had been transported through TAPS.⁹⁸

64. TAPS' design capacity of 1.42 million bbl/d has not been changed, except that a strategic reconfiguration ("SR") project of the pumps has been undertaken over the past several years. In that project, some of the original Legacy pumps have been taken out of service and others have been replaced with new variable speed pumps. The current physical capacity of the operating pumps on TAPS is 1.1 million bbl/d.⁹⁹ The mechanical capacity of those pumps is 760,000 bbl/d. Adding DRA to the oil increases the ability of the upgraded SR pumps to transport up to 1.1 million bbl/d. Alyeska has described the goal of SR as follows: "to position TAPS for more effective operation while maintaining or enhancing safety, operational integrity and environmental performance. The new system is modular and scalable and will provide flexibility for future increases or decreases in throughput."¹⁰⁰

65. Jeff Ray of ExxonMobil Pipeline Company testified that the Owners are not currently maintaining 1.1 million bbl/d of physical capacity because two of the DRA injection sites can only use an older form of DRA. However, Mr. Ray also indicated that those two sites could be quickly modified to be able to use the newer DRA for "probably a couple million dollars," which would then bring the physical capacity to 1.1 million bbl/d.¹⁰¹ Accordingly, this Court finds that TAPS' physical capacity during each of the lien years,

⁹⁸ TO-07-0004.0408.

⁹⁹ MUN7-0215 at 107; Tr. 7037 (Ray).

¹⁰⁰ MUN7-1103 at 56. See also Tr. 2728-30 (Falcone).

¹⁰¹ Tr. 7049-51 (Ray).

including its SR pumps and with DRA, was 1.1 million bbl/d. The design capacity of the mainline pipe and the VMT remained at 1.42 million bbl/d during each of the lien years.

D. Limited-Market Property

66. TAPS is a limited-market property because there is a very limited market for the purchase and sale of any ownership interest in TAPS. When interests in TAPS have changed hands, the buyers have purchased those interests as part of a broader transaction that has included the buyers' use of TAPS to transport ANS product to market. Each of the Owners has a right of first refusal should any other Owner elect to sell its interest in TAPS.¹⁰²

67. TAPS' limited market or market participants are best defined as the shippers on TAPS – the ANS producers. It is these producers that would pay for TAPS, or if hypothetically TAPS did not exist as of the assessment dates, would pay to build or replace TAPS.¹⁰³

E. Special-Purpose Property

68. TAPS is also a special-purpose property. It was specifically designed, constructed, and adapted for its particular use – to move affiliated crude oil from the ANS to Valdez. The ANS represents about 15% of the U.S. domestic crude oil production and TAPS is the only viable means of transporting that oil to market.¹⁰⁴

F. Integrated Economics

69. The TAPS Owners did not and could not have independently financed the original construction of TAPS and they do not independently finance substantial

¹⁰² Tr. 11355-56 (Podwalny); Tr. 11903 (Remsha).

¹⁰³ Tr. 11978 (Remsha); Tr. 12798 (Greeley).

¹⁰⁴ MUN7-0001 at 410; Tr. 8206-07, 8211 (Cicchetti).

improvements to TAPS. Instead, the affiliated production companies have financed TAPS' construction. And the evidence at trial demonstrated that all significant funding decisions for TAPS are not made by the TAPS Owners, but by the affiliated parent corporations or upstream producer affiliates of each Owner.¹⁰⁵

70. As of the lien dates, the parent companies of the three largest owners of TAPS (BP, ConocoPhillips, and ExxonMobil) had a combined 95% ownership interest in TAPS.¹⁰⁶ These same three parent companies also had a combined total in excess of 96% of the estimated production on the North Slope.¹⁰⁷ This close correlation between estimated production and ownership interest in TAPS is expected to remain in place for the foreseeable future.¹⁰⁸ One of the other two TAPS Owners, Unocal, has an affiliate (Chevron) with substantial ANS production. The other TAPS Owner, Koch Alaska Pipeline Company, has an affiliate whose contract with the State provides it with oil for delivery to the largest refinery connected to TAPS (Flint Hills). Thus, each of the five TAPS Owners has an affiliate with oil to be transported on TAPS.¹⁰⁹

71. Each Owner's affiliated producer has an economic incentive to nominate its ANS production to its affiliated TAPS Owner. As explained by Charles Coulson, the President of BP Pipelines:

There has been a strong pattern of shippers on TAPS nominating their barrels to affiliated pipeline companies. There are a variety of reasons for this behavior, but mostly it can be understood by thinking about integrated corporate economics. When an upstream affiliate

¹⁰⁵ See, e.g., Tr. 2708-09 (Falcone)

¹⁰⁶ Tr. 8550 (Sullivan). See also MUN7-0001 at 983 (Coulson).

¹⁰⁷ Tr. 8551 (Sullivan); MUN7-0001 at 971 (Coulson).

¹⁰⁸ MUN7-0001 at 984 (Coulson); Tr. 9272-74 (Platt).

¹⁰⁹ MUN7-0001 at 984 (Coulson).

ships barrels in its pipeline affiliate's space, it pays the published tariff rate to the pipeline affiliate, and no money leaves the corporate family.¹¹⁰

72. In addition to serving as President of BP Pipelines, Mr. Coulson is Vice President of BP Shipping US. He explains, "those two roles allow me to manage BP's midstream assets here in Alaska."¹¹¹ Mr. Coulson's paycheck is from BP Exploration (Alaska), Inc. ("BPXA"); BP Pipelines does not maintain any bank accounts.¹¹² Accordingly, the TAPS tariffs that BP Pipelines collects are not paid to it but to another BP affiliate.¹¹³ And if Alyeska proposed that the Owners expend money for a large project on TAPS, Mr. Coulson testified that BP would assess whether it fits with "what we want to do in Alaska corporately,"¹¹⁴ with funding determinations for TAPS made by BP's upstream executive group.¹¹⁵

73. And yet while four of the five Owners are vertically integrated oil companies, there is no evidence that they operate collusively together as an economic unit or in concert with other producing or refining entities as an economic unit. Likewise, the proven reserves owned by an affiliate of one TAPS Owner are not integrated with the proven reserves of an affiliate of another TAPS Owner or with the proven reserves of an unaffiliated producer.¹¹⁶

¹¹⁰ MUN7-0001 at 984 (Coulson FERC Testimony, April 13, 2010). *See also* MUN7-0001 at 2411 (Jaffe Affidavit) ("The movement of petroleum through the pipeline is dominated by shipments in which the shipper is among the corporate affiliates of the carriers."); Tr. 7728-7729 (Toof); Tr. 8195 (Cicchetti).

¹¹¹ MUN7-0001 at 3717.

¹¹² MUN7-0001 at 3740.

¹¹³ MUN7-0001 at 3749.

¹¹⁴ MUN7-0001 at 3753.

¹¹⁵ MUN7-0001, 3751-53.

¹¹⁶ Tr. 7391 (Falcone).

G. Unique Regulatory Status

74. TAPS is a regulated pipeline, regulated by both the Regulatory Commission of Alaska (“RCA”) and the Federal Energy Regulatory Commission (“FERC”).

75. During the first several years of TAPS’ operation, the amount of the tariff was in litigation. In 1985, the Owners and the State entered into the TAPS Settlement Agreement (“TSA”). For the next two decades, the tariffs were based on the TAPS Settlement Methodology (“TSM”) and were not evaluated under the just and reasonable standard.¹¹⁷ The TSM front-end loaded the recovery of the initial cost of TAPS to such a degree that the original investment was largely recovered by the late 1990s – decades before any reasonable estimate of the end of TAPS’ economic life.¹¹⁸

76. The TSM also allowed an accelerated recovery of return in the form of an allowance per barrel. The RCA held that the TSM resulted in \$9.9 billion (nominal dollars) or \$13.5 billion (1997 dollars) more than would otherwise have been permitted under traditional cost of service regulation.¹¹⁹ The higher tariffs during that time also resulted in lower production tax liability for the affiliated producers.

77. The TSA expired in 2005. Since then, there has been considerable litigation before FERC and the RCA with respect to the TAPS tariffs.

¹¹⁷ *BP Pipelines (Alaska), Inc.*, 119 F.E.R.C. ¶ 63,007 at ¶¶ 48, 54 (2007).

¹¹⁸ Tr. 8567 (Sullivan).

¹¹⁹ Tr. 8567 (Sullivan); MUN7-0001 at 1274.

IV. PREMISE OF VALUE

78. A premise (or standard) of value is included in all assessments and appraisals of property.¹²⁰

79. The statutory premise of value in AS 43.56.060(e)(2) was interpreted by this Court in the Amended Decision.¹²¹ Although this Court vacated the August 8, 2011 Collateral Estoppel Order for the 2007 through 2009 tax years and allowed the parties to present additional evidence and arguments regarding the premise of value at the trial de novo, this Court has not been persuaded that the conclusions reached by this Court in the Amended Decision regarding the premise of value should be abandoned, but has determined that they should be further refined as discussed herein. Further, this Court has also more thoroughly studied the legislative history of the statute as discussed below.

80. The terms “economic value” and “full and true value” have no generally accepted definitions in the appraisal profession.¹²²

81. Different concepts of value arise from economic principles, including the concepts of value in exchange and use value.¹²³ Value is never a fact but always an opinion of worth at a given time in accordance with a definition of the standard of value.¹²⁴

82. Value in exchange is also referred to as market value.¹²⁵ This concept generally is expressed as the amount that a willing buyer will pay and a willing seller will

¹²⁰ American Society of Appraisers, *Valuing Machinery and Equipment: The Fundamentals of Appraising Machinery and Technical Assets 2* (2d ed. 2005) [hereinafter *Valuing Machinery and Equipment*].

¹²¹ Amended Decision ¶ 95.

¹²² Tr. 11897-10 (Remsha); Tr. 12203, 12230-31 (Marchitelli). See also Amended Decision ¶ 64.

¹²³ See generally Appraisal Institute, *The Appraisal of Real Estate* 15-32.

¹²⁴ Tr. 513-14 (Remsha).

¹²⁵ *The Appraisal of Real Estate* at 23.

accept, in an arm's length negotiation, to transfer the property, with both buyer and seller being knowledgeable about the property.¹²⁶ Market value is a transactional-based concept.¹²⁷

83. "Use value is the value a specific property has for a specific use. In estimating use value, the appraiser focuses on the value the real estate contributes to the enterprise of which it is a part without regard to the highest and best use of the property or the monetary amount that might be realized from its sale."¹²⁸ "If a property's current use is so specialized that there is no demonstrable market for it but the use is viable and likely to continue, the appraiser may render an opinion of use value if the assignment reasonably permits a type of value other than market value. Such an estimate should not be confused with an opinion of market value."¹²⁹

84. Market value and use value can be the same value if the highest and best use of the property is its current use.¹³⁰

85. Use value is distinct from investment value. "Investment value is the value of a property to a particular investor based on that person's (or entity's) investment requirements. In contrast to market value, investment value is value to an individual, not necessarily value in the market."¹³¹ *The Appraisal of Real Estate* describes investment value as a "subjective"

¹²⁶ *The Appraisal of Real Estate* at 23.

¹²⁷ *The Appraisal of Real Estate* at 22-25.

¹²⁸ *The Appraisal of Real Estate* at 27. "The term 'value in use' is often used by appraisers synonymously with 'use value,' but the former term has specific meanings in other contexts, which can cause confusion." *The Appraisal of Real Estate* at 28.

¹²⁹ *The Appraisal of Real Estate* at 28.

¹³⁰ Tr. 408 (Swain); Tr. 508-09, 515 (Remsha); Tr. 10342-48 (Tegarden); Tr. 12209 (Marchitelli); Tr. 12962-3 (Greeley); Tr. 958 (Eyre); Tr. 875 (Podwalny); Tr. 11632-33 (Hoffbeck).

¹³¹ *The Appraisal of Real Estate* at 28-29.

type of value, and this Court has not interpreted the applicable statute as creating an investment value standard.

86. The Legislature's references in AS 43.56.060(e)(2) to "full and true value" and "economic value," along with its omission of the terms "open market," "willing seller and willing buyer," and "the estimated price that the property would bring in an open market," reflect an intent to accord flexibility to the Division and SARB when valuing pipeline property, particularly unique pipeline property like TAPS.¹³²

87. That the Legislature could have required, but chose not to require, that the premise of value for pipeline property be a market value standard, lies in its omission of the terms "open market" and "willing seller and willing buyer" to describe the premise of value for such property – in contrast to its use of those terms for other property such as exploration property under AS 43.56.060(c).¹³³

88. That AS 43.56.060(e) does not mandate a market value standard for the valuation of pipeline properties is fully supported by the legislative history.

89. In October 1973 two parallel bills, HB 1 and SB 1, were introduced by Governor Egan during a special session of the Alaska Legislature.¹³⁴ A version of HB 1 was

¹³² The rule of statutory construction that where a form of conduct, the manner of its performance and operation, and the persons and things to which it refers is expressly designated, there is an inference that all omissions should be understood as exclusions clearly is applicable here. See, e.g., Norman J. Singer and J.D. Shambie Singer, 2A *Sutherland Statutory Construction* § 47:23 at 417 (7th ed. 2007) ("The force of the maxim is strengthened where a thing is provided in one part of the statute and omitted in another.") (citation omitted). See also *Ranney v. Whitewater Engineering*, 122 P.3d 214, 218-19 (Alaska 2005); *Croft v. Pan Alaska Trucking, Inc.*, 820 P.2d 1064, 1066 (Alaska 1991) (explaining that application of this principle of statutory construction "is particularly compelling where, as here, the scheme is purely statutory and without a basis in the common law"). Cf. Owners' Proposed Findings of Fact and Conclusions of Law ¶ 29. The parenthetical referencing of Sutherland's 6th Edition that is set forth in that proposed finding could not be located in that treatise.

¹³³ See also AS 29.45.110(a).

¹³⁴ H.J. at 4-6, 8th Leg., 1st Spec. Sess. (Alaska 1973) (letter from William A. Egan introducing HB 1); S.J. at 4-5, 8th Leg., 1st Spec. Sess. (Alaska 1973) (letter from William A. Egan introducing SB 1).

ultimately passed by the Legislature as the oil and gas property taxation statutes, AS 43.56.010 *et seq.*¹³⁵

90. At the time of the special session, pipeline construction was imminent. Other bills had been introduced the previous year but failed to make it out of committee.¹³⁶ The 1973 legislative history demonstrates a tangible awareness of the time constraints imposed by the special session.¹³⁷

91. Likely as a function of this time pressure, committee discussions of HB 1 were not always precise. On occasion, they blurred distinctions between methods of valuation, standards of valuation, depreciation bases, and types of property.

92. Much of the discussion surrounding HB 1 focused on the destination of the tax revenue and concerns about the creation of new "pipeline boroughs." The legislative history of AS 43.56.060 is not extensive, but what does exist is indicative of a legislative intent to give assessors the tools and flexibility so as to permit assessed valuations to be increased over time, as warranted.¹³⁸

¹³⁵ Specifically, a Senate Free Conference Committee substitute for a Senate Finance Committee Substitute for a House Finance Committee substitute for HB 1 was enacted. S.J. at 129.

¹³⁶ HB 460 [2007 R. 9472]; HB 598 [2007 R. 9492].

¹³⁷ See, e.g., *Minutes* at 88, H. Comm. Community and Regional Affairs, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 3, 1973) (Committee Report on Senate CS for CS for HB 1) ("There is no doubt also that we could produce a better bill if we had more time . . .") [2007 R. 9845]; *Minutes* at 139, S. Finance Comm., 1st Spec. Sess. (Alaska 1973) (Nov. 8, 1973) ("Sen. Palmer noted the effect of [the assessment] section was several years down the line, and he thought it would be more expedient to accept the House version at this time.") [2007 R. 9861]; *Minutes* at 10, S. Free Conference Comm., 1st Spec. Sess. (Alaska 1973) (Nov. 10, 1973) (Rep. Freeman presented the Committee's options as "deadlock" or "accept[ing] the mediocre bill before them"; within an hour, the Committee adopted the bill version that became the statute.) [2007 R. 9871].

¹³⁸ See, e.g., *Minutes* at 21, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) ("Mr. Condon, Assistant Attorney General, answered that with respect to production property, the value would be less using that approach. With respect to the pipelines, they use actual cost depreciation on an annual straight line allowance with no inflation factor. He said their pipeline formula would tend to lead to higher valuation.") [2007 R. 9708]; *Minutes* at 22, H. Finance Comm., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) ("Mr. Fink said valuations of this type of property seem difficult. He asked whether they couldn't take advantage of increased value.") [2007 R. 9710].

93. The Owners assert that at the time AS 43.56.060 was drafted, “economic value” was consistent with “market value” and that “the term economic value was at least partially familiar to legislators as being a reference to an assessment methodology using an income stream.”¹³⁹ The Court finds this argument unavailing. In support of this assertion, the Owners cite to a sentence in a memorandum by a fiscal analyst to the Speaker of the House of Representatives dated October 17, 1973, prior to the House taking up HB 1.¹⁴⁰ The sentence reads: “Various methods and factors can be considered in arriving at assessed value including actual cost and the economic value or income stream the line is capable of producing.”¹⁴¹ The memo makes no reference to market value.¹⁴²

94. AS 43.56.060 contains different definitions of “full and true value” for different types of property. In general terms, it specifies market value for exploration property, use of replacement cost less depreciation for production property, and economic value for transportation (pipeline) property.

95. In its original form, HB 1 set forth three approaches for the three types of property. Language that was not retained in the bill as finally enacted into AS 43.56.060 is italicized:

- Exploration property was to be assessed using market value: “the estimated price which the property would bring in an open market and under the then prevailing market conditions in a sale between a willing seller and a willing

¹³⁹ Owners’ Proposed Findings of Fact and Conclusions of Law ¶¶ 26, 35.

¹⁴⁰ R. 9922-23.

¹⁴¹ R. 9922-23.

¹⁴² R. 9922-23.

buyer both conversant with the property and with prevailing general price levels.”¹⁴³

- Production property was to be assessed “on the basis of *actual cost* less depreciation based on *units of production*.”¹⁴⁴
- Transportation property was to be assessed “with due regard to the economic *life* of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically and legally deliverable into the transportation facility.”¹⁴⁵

96. The assessment of production and transportation property received most of the attention in legislative deliberations. The minutes reflect that Attorney General John Havelock was actively involved with earlier versions of the bill,¹⁴⁶ was present at many of the House and Senate committee meetings, and the majority of the committees’ valuation questions were directed to him.

97. HB 1 was referred to the House Finance Committee on October 17, 1973.¹⁴⁷ The House Finance Committee substitute (“HFCS”) was adopted by the House on October 29, 1973.¹⁴⁸

98. The House Finance Committee minutes indicate that the Committee considered and rejected both a market value approach and a reliance on the pipeline’s value for rate regulation purposes for assessing transportation property.

¹⁴³ H.B. 1, 8th Leg., 1st Spec. Sess. (Alaska 1973) [2007 R. 9645].

¹⁴⁴ H.B. 1, 8th Leg., 1st Spec. Sess. (Alaska 1973) [2007 R. 9645].

¹⁴⁵ H.B. 1, 8th Leg., 1st Spec. Sess. (Alaska 1973) [2007 R. 9645].

¹⁴⁶ See, e.g., 2007 R. 9541 (Attorney General Havelock answering questions about HB 59, a predecessor bill, before the House Resources Committee earlier in 1973) (specific date unavailable).

¹⁴⁷ H.J. at 4, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 17, 1973) [2007 R. 9903].

¹⁴⁸ H.J. at 58, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 29, 1973) [2007 R. 9911].

99. The minutes also indicate that the Committee considered an actual cost valuation and a units-of-production depreciation method. At a hearing, Homer Burrell, then Director of the Division of Oil and Gas, asked the Committee, "How can you determine the full and true value of a \$4 billion installation." One representative indicated that "the actual cost of construction conceivably could be the full and true value. Original construction costs could be used, and appreciated or depreciated accordingly." Mr. Burrell responded: "this apparently allows for inflation and deflation but that is all. When the oil is gone, [the pipeline] is worthless, although it still could be appraised at \$4 billion. Units of production tie [the pipeline] to its economic life, but its physical life must be considered also." Mr. Burrell indicated that the uncertainty lay with whether the pipeline's physical life would be shorter or longer than its economic life. He added, "units of production depreciation covers the pipeline as long as there is oil going through it."¹⁴⁹

100. When the subject of market value was raised, Attorney General Havelock's response was focused on production property:

Mr. Fink referred to the method of valuation. He noted they had heard testimony and a good argument made for value of property at fair market value as opposed to their method. He wondered whether the method would make much difference.

Mr. Havelock replied it would be a considerable change. The fair market value method would introduce an element of uncertainty in property that doesn't have a fair market value. He said the question was whether they were going to value production equipment on fair market value and create considerable uncertainty because there was not the same kind of market in production facilities. He asked how they would figure fair market value excluding intangibles that would go into the price. He didn't think the fair market value was appropriate,

¹⁴⁹ *Minutes* at 50, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973) [2007 R. 9735].

and added that from the industry point of view it would give uncertainty because it would depend on the assessor.¹⁵⁰

101. The House Finance Committee also discussed reliance on the pipeline's value for regulatory purposes, or "the ICC approach," so named after FERC's predecessor agency, the Interstate Commerce Commission.¹⁵¹ The Committee minutes indicate that the approach was dismissed by Attorney General Havelock:

Mr. Malone asked if it wouldn't simplify things if they just used the valuation placed on the pipeline for return by ICC. Mr. Havelock said no . . . Mr. Malone thought it would simplify the State's assessment procedure and put it on a parity with the tariff [sic]. Mr. Havelock didn't think the State's problem was that complex.¹⁵²

102. In this regard Larry Eppenbach, Deputy Commissioner of the Treasury, stated:

Mr. Fink asked whether Mr. Eppenbach thought the value of the pipeline would go down over fifty years. Mr. Eppenbach believed ICC will reduce valuation from time to time and not increase it. . . . Mr. Eppenbach said that every indication they got was that ICC would reduce the value.¹⁵³

103. Thus, the legislative history supports a conclusion that the House specifically considered and rejected an assessed value standard equal to the pipeline's value for rate-making purposes.

104. During the same legislative session at which HB 1 was introduced, an alternate bill, HB 9, was introduced to the House on October 22, 1973 and referred to the

¹⁵⁰ *Minutes* at 21, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9708].

¹⁵¹ *Minutes* at 21, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9708].

¹⁵² *Minutes* at 23-24, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9711-12].

¹⁵³ *Minutes* at 22-24, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 20, 1973) [2007 R. 9710-12].

House Finance Committee.¹⁵⁴ HB 9 addressed exploration, production, and transportation property together in a single provision, and provided that the full and true value of all three types of property would be “the estimated price which the property would bring in an open market and under the then prevailing market conditions in a sale between a willing seller and a willing buyer both conversant with the property and with prevailing general price levels.”¹⁵⁵ The House Finance Committee minutes do not reflect any discussion of HB 9, suggesting that the House was not interested in a unilateral market value approach to value the three different types of property.

105. After its adoption by the House on October 29, 1973, HFCS was sent to the Senate Finance Committee, which produced a committee substitute (“SFCS”) that was forwarded to the Senate on November 8, 1973.

106. SFCS contained the final language for the ad valorem assessment of transportation property that appears in AS 43.56.060(e). It trimmed down HFCS by removing the “replacement cost” component added by the House, and substituted “economic value” for “economic life” for transportation property.¹⁵⁶ The following excerpts from the Senate Finance Committee minutes are informative:

Referring to sub-section (2), page 5, line 7, Sen. Groh said the House version used replacement costs less depreciation versus the original version which used actual costs. Sen Palmer said this approach was used in the Kenai borough and it appeared satisfactory. Sen. Palmer moved the adoption of the House version. Sen. Groh noted there was

¹⁵⁴ H.J. at 25, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 22, 1973). Another bill, HB 10, was introduced October 25, 1973, and adopted the assessment language of HFCS wholesale. H.J. at 34, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Oct. 25, 1973); H.B. 10, 8th Leg., 1st Spec. Sess. (Alaska 1973) (offered Oct. 25, 1973) [2007 R. 9635-37].

¹⁵⁵ H.B. 9, 8th Leg., 1st Spec. Sess. (Alaska 1973) (offered Oct. 22, 1973) [2007 R. 9629].

¹⁵⁶ Senate CS for CS for HB 1, S. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (offered Nov. 8, 1973) (emphasis added) [2007 R. 9667].

a substantial difference between Kenai and a \$4.5 billion pipeline, and the committee discussed which version should be adopted. Sen. Lewis moved to replace the word "replacement" with "actual." Sen. Ray said fair market value would be more appropriate. Sen. Groh referred to the motion made by Sen. Lewis [to change "replacement" to "actual"], and Sen. Palmer asked that the record show the vote on this now was no commitment to the future. The motion passed by a vote of 4 to 3.

...
Sen. Groh asked if there were any other suggestions regarding CSHB 1, and Sen. Ray said there were still problems with actual versus replacement costs. After discussion, Sen. Palmer noted the effect of this section was several years down the line, and he thought it would be more expedient to accept the House version at this time. Mr. Havelock said the Governor's version had different language, and the House version would not produce as much revenue. Sen. Palmer moved to rescind the committee's previous action [replacing "replacement" with "actual"]; upon vote the motion was accepted by a vote of 4 to 3. Sen. Butrovich moved and asked unanimous consent to adopt the Governor's wording ["with due regard to the economic life of the property"] in this section, and then amended his motion to include substituting "economic value" for "economic life." No objection, so ordered.¹⁵⁷

107. Although the details of this deliberative process are difficult to discern, what can be gleaned from this otherwise opaque account is that the Senate Finance Committee did not seriously consider a market value approach, as it was mentioned only in passing and not voted upon.¹⁵⁸

108. Based on this Court's review of the legislative history, an ICC-based or regulatory valuation was not discussed in the Senate.

¹⁵⁷ *Minutes* at 138-39, S. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 8, 1973) [2007 R. 9860-61].

¹⁵⁸ *Minutes* at 138-39, S. Finance Comm., 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 8, 1973) [2007 R. 9860-61] ("Sen. Ray said fair market value would be more appropriate.").

109. The bill then went to a Free Conference Committee.¹⁵⁹ There, the House attempted to negotiate a return to “replacement cost” instead of “economic value” for the valuation of pipeline property in exchange for other concessions, but was unsuccessful.

110. The legislative history demonstrates that the House had a preference for valuing transportation property using an explicit “replacement cost” approach, while the Senate preferred an apparently less restrictive “economic value” approach, which Attorney General Havelock had advised Legislators would produce more revenue, and in the end, the Senate prevailed on this issue.

111. In its closing argument at the trial de novo before this Court, the Department stated that the legislative history, taken as a whole, “demonstrates some likelihood that the Legislature was fully cognizant of a willing buyer/willing seller standard when it enacted 43.56.060(e)(2).”¹⁶⁰ This Court agrees and further finds that the Legislature was also cognizant that the pipeline would be valued by the ICC for rate making purposes, and did not adopt such a premise for ad valorem tax purposes.

112. The Owners assert that the “Alaska tax system will not function properly if a pipeline valuation methodology is adopted that does not take governmentally established tariff levels into account.”¹⁶¹ They maintain that because the production tax is computed after the deduction of pipeline tariffs, “TAPS property tax value must take into account actual tariff income.”¹⁶² To do otherwise, the Owners maintain, “whipsaws North Slope producers

¹⁵⁹ H.J. at 140, 8th Leg., 1st Spec. Sess. (Alaska 1973) (Nov. 10, 1973) [2007 R. 9913].

¹⁶⁰ Tr. 13272-73 (Department’s closing).

¹⁶¹ Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 787.

¹⁶² Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 786.

and pipeline transportation companies, taxing pipeline companies as if they received high tariff income but taxing producers as if they incur low tariff expense.”¹⁶³

113. But this Court finds that valuing the pipeline without exclusive reliance on the tariff income does not result in taxing the pipeline companies as if they received a high tariff income. Rather, an assessed valuation that exceeds the net present value of the projected tariff income stream recognizes that the value of the pipeline exceeds that tariff income stream. This Court has previously determined, and again holds, that “the term ‘economic value’ as set forth in AS 43.56.060(e)(2) does not mandate, as a matter of law, the exclusive reliance on the regulated tariff income to value TAPS.”¹⁶⁴

114. In the case of TAPS, AS 43.56.060(e)(2)’s reference to “economic value” and not “market value” is consistent with the reality that there is no market for TAPS as a stand-alone investment based solely on its tariff income. Even if there might be a buyer of TAPS based solely on its tariff income, the evidence at the trial de novo conclusively demonstrated that a TAPS Owner would not sell its interest in TAPS without the assurance that its affiliated oil from the Alaska North Slope could be shipped to market. At trial, the Owners’ appraisal expert Michael Remsha was asked if he believed that the TAPS Owners would sell TAPS to a “rich sheikh from Saudi Arabia”¹⁶⁵ for \$20 billion “for the expressed purpose of shutting [TAPS] down.”¹⁶⁶ Mr. Remsha replied that the Owners would “[m]ost likely not” sell

¹⁶³ Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 786.

¹⁶⁴ See Order on Summary Judgment Motions at 5 (Sept. 24, 2007).

¹⁶⁵ Tr. 690 (Remsha).

¹⁶⁶ Tr. 692 (Remsha).

their interests in TAPS at that price under those circumstances, “[b]ecause they want to be able to have the opportunity to take oil from the North Slope and bring it to market.”¹⁶⁷

115. Highest and best use generally considers the most probable use that is physically possible, legally permissible, financially feasible, maximally productive, and results in the highest value.¹⁶⁸ The purpose of a highest and best use analysis is to evaluate alternative uses to assist the appraiser in determining the use which creates the highest value of the property.

116. A highest and best use analysis is not required to be made when valuing property under non-market value standards, including a use value standard, because a use value appraisal is literally valuing the current use.¹⁶⁹ Nonetheless, a highest and best use analysis can be helpful in considering the full and true value of TAPS. “The highest and best use of special-use property as improved is probably the continuation of its current use if that use remains viable.”¹⁷⁰ The highest and best use of TAPS is its current use – the transport of ANS oil to market.¹⁷¹ This use is physically possible, legally permissible, and maximally productive. TAPS would not provide maximum value on a standalone basis.

117. The fee simple interest, as an analytical tool, includes the full bundle of rights subject only to the four powers of government: police power, escheat, eminent domain, and taxation.¹⁷² The taxable property does not include any external interest held by third parties

¹⁶⁷ Tr. 692 (Remsha).

¹⁶⁸ *The Appraisal of Real Estate* at 278; *Valuing Machinery and Equipment* at 212.

¹⁶⁹ Tr. 12536 (Goodwin).

¹⁷⁰ *The Appraisal of Real Estate* at 294.

¹⁷¹ Tr. 692 (Rein); Tr. 8196 (Cicchetti); MUN7-0001 at 3767 (Coulson).

¹⁷² *The Appraisal of Real Estate* at 122.

who are not TAPS Owners, including any alleged "Shippers' interests."¹⁷³ When valuing TAPS for ad valorem tax purposes, the only interests that are valued are the TAPS Owners' undivided fee simple property interests in TAPS' taxable property. The right of a shipper to transport crude oil in a common carrier pipeline does not transfer a portion of the pipeline owner's fee simple property interest to that shipper.¹⁷⁴

118. TAPS is a regulated common carrier pipeline and must accept and transport tendered oil for transportation without discrimination.

119. The Owners have asserted that the government regulation of the rates for transport on TAPS is a form of police power that diminishes the value of TAPS.¹⁷⁵ Regulation may diminish the value of the regulated property.¹⁷⁶ But as several witnesses testified at the trial, regulation may also have no effect on a property's value or increase its value.¹⁷⁷ This Court has previously held and again finds that an assessment must consider the extent to which the exercise of police power or any other governmental power impacts the value of the particular property being assessed. The Owners presented Professor Swain, Mr. Tegarden, and Mr. Marchitelli as theory witnesses, none of whom offered an opinion on whether regulation resulted in an increase or decrease in TAPS' ad valorem value, but indicated that the effects of rate regulation had to be taken into account.¹⁷⁸

¹⁷³ Tr. 12204-05 (Marchitelli).

¹⁷⁴ Tr. 12205-08 (Marchitelli). Cf. Tr. 12915-17 (Greeley).

¹⁷⁵ In this regard, the Owners appear to substantially misquote the definition of police power from *The Appraisal of Real Estate* in their proposed findings. The definition from that text does not identify either "income restrictions" or "rate regulations" as forms of police power. Compare Owners' Proposed Finding ¶ 789 with *The Appraisal of Real Estate* at 122.

¹⁷⁶ *Wash. Gas Light Co. v. Baker*, 188 F.2d 11, 19 (D.C. Cir. 1950) (citing *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 601 (1944)).

¹⁷⁷ Tr. 447 (Swain); Tr. 10318-10320 (Tegarden); Tr. 12258 (Marchitelli).

¹⁷⁸ Tr. 449 (Swain); Tr. 10318-10320 (Tegarden); Tr. 12261:25-12262:14 (Marchitelli).

120. Assuming, without deciding, that rate regulation is a form of police power, it does not alter the premise of value for TAPS, nor does it require that TAPS be valued for ad valorem tax purposes at the net present value of its projected tariff income. Rather, it requires the assessor to consider whether and to what extent rate regulation impacts the value of TAPS. Under a cost approach to valuation, this issue can be determined when addressing the degree of any economic obsolescence caused by rate regulation.

121. FERC and the RCA do not have jurisdiction to determine the proper value of TAPS for state ad valorem tax purposes. Their valuations of TAPS for purposes of establishing a tariff do not inform this Court as to the value of TAPS for ad valorem tax purposes under AS 43.56.060(e)(2).¹⁷⁹

122. In 2007, SARB addressed the Owners' assertion that the assessed value of TAPS cannot exceed the value of its regulated tariff income stream.¹⁸⁰ The Board found that "[a] regulated tariff does not produce an income that would capture the current economic value of the pipeline."¹⁸¹ Further, SARB concluded that "uncertainty about future tariff rates makes any valuation based on the capitalization of future tariffs very unreliable."¹⁸²

123. SARB correctly concluded that tariff income is not the appropriate determinant of the full and true value of TAPS in the applicable tax years.¹⁸³ Mr. Hoffbeck's observations

¹⁷⁹ See *Tenn. Gas Pipeline Co. v. Town of Hudson*, 766 A.2d 672, 675-76 (N.H. 2000) (holding that replacement cost method, not net book cost method, was the proper method for valuing the pipeline company's FERC-regulated property).

¹⁸⁰ MUN7-0234 at 13.

¹⁸¹ MUN7-0234 at 13.

¹⁸² MUN7-0234 at 13.

¹⁸³ See MUN7-0234 at 16; MUN7-0236 at 28 – 30.

on Mr. Mark's testimony that the bulk of the physical assets that are being valued in this case are no longer included in TAPS' rate base demonstrate that a tariff-based approach would fail to value all of TAPS.¹⁸⁴ Case law throughout the nation makes clear that, even under a market value standard, courts do not typically equate net book earnings with value for ad valorem tax purposes.¹⁸⁵

124. As in the 2006 matter, this Court finds that Mr. Podwalny's description of TAPS as a non-investment property within each Owner's integrated system is consistent with the statute and best supports the Division's and SARB's determination with respect to the economic value of TAPS.¹⁸⁶ To the extent that there is a market for TAPS, it is the ANS producers (or an integrated refinery operation such as Koch). For the evidence persuasively demonstrates that ANS producers would rebuild TAPS at a cost of billions of dollars to transport ANS petroleum products to market if TAPS was not in existence as of the lien dates. And the producers would replace TAPS not for the tariff income they might realize, but to monetize the approximately 7 to 8 billion barrels of proven reserves that were at the ANS as of the lien dates.

¹⁸⁴ Tr. 1241-22 (Hoffbeck).

¹⁸⁵ See *Tennessee Gas Pipeline Co. v. Town of Hudson*, 766 A.2d 672, 675-676 (N.H. 2001); *Polk County v. Tenneco, Inc.*, 554 S.W.2d 918, 922-23 (Tex. 1977) (concluding that the net book value did not measure the market value for the entire pipeline's property); *Boston Edison Co. v. Board of Assessor of Watertown*, 439 N.E.2d 763, 766-67 (Mass. 1982) (net book cost of property does not set an upper limit on the property's value for location taxation); *Appeal of Public Serv. Co. of N.H.*, 471 A.2d 1182, 1185-86 (N.H. 1984) (rejecting the taxpayer's argument that evidence demanded a finding that net book value was an appropriate measure of market value for all of utility's property); *Public Service Co. of N.H. v. Town of Ashland*, 377 A.2d 124, 125-26 (N.H. 1977) (holding that even though net book value provides the "rate base" upon which plaintiff's rate of return is calculated, the value of the property for tax purposes and the value for rate making purposes need not be the same); *Public Services Co. v. New Hampton*, 136 A.2d 591, 597 (N.H. 1957) (holding that value of property for tax purposes and its value for rate making purposes need not be the same).

¹⁸⁶ Amended Decision ¶ 91.

125. For the reasons set out above, this Court finds that SARB's determinations for the three tax years at issue, which strived to determine the full and true value of TAPS based on the economic value of its continued use in transporting ANS proven reserves to market, has not been demonstrated to constitute a fundamentally wrong principle of valuation.¹⁸⁷

V. THE OWNERS' MAINTENANCE OF TAPS' CAPACITY OF 1.1 MILLION BBL/D WITH UPWARD SCALABILITY TO 2.1 MILLION BBL/D

126. TAPS' current design capacity is 1.42 million bbl/d.¹⁸⁸ However, some of the original Legacy pumps have been taken out of service and new SR pumps are being installed at four pump stations. The current upgraded pumps are able to transport up to 1.1 million bbl/d on a yearly average with a maximum of 1.14 million bbl/d during winter months.¹⁸⁹ With additional modular pumps, TAPS' current physical capacity can be increased. For example, Mr. Falcone indicated that if two additional pump stations were added, TAPS could transport 1.5 million bbl/d.¹⁹⁰

127. Although TAPS cannot immediately transport 2.1 million bbl/d, the evidence persuasively establishes that with sufficient lead time, TAPS as currently configured is able to transport any volume up to 2.1 million bbl/d, should the need arise, with the installation of additional pumps and use of DRA.

¹⁸⁷ Amended Decision ¶ 92.

¹⁸⁸ Tr. 7367 (Falcone); MUN7-0215 at 258.

¹⁸⁹ Tr. 7139-7143 (Ray).

¹⁹⁰ Tr. 2730 (Falcone).

128. DB-180 is an Alyeska document that evidences the design basis for TAPS. DB-180 indicates at four places that a throughput range for TAPS is 300,000 to 2.1 million bbl/d.¹⁹¹ DB-180 also references the maximum or ultimate throughput of 2.1 million bbl/d in an additional four places in the document.¹⁹² Thus, there are eight different places in DB-180 that specifically refer to a 2.1 million bbl/d standard as the maximum throughput of TAPS.

129. In accordance with the requirements of DB-180, the mainline pipe is currently maintained at a 2.1 million bbl/d throughput standard.¹⁹³ The evidence at trial persuasively demonstrates that neither the mainline 48-inch pipe nor any other part of TAPS is maintained based upon the current throughput or DOR forecasts for future production, but is instead maintained for considerably higher potential throughputs.¹⁹⁴

130. Any proposed design change to DB-180 must be approved by the Joint Pipeline Office.¹⁹⁵ No evidence was introduced to demonstrate that DB-180's design criteria have been changed.¹⁹⁶ The Court finds that DB-180 continues to be the controlling document with regard to the design basis for TAPS, and that document sets forth 2.1 million bbl/d as the maximum throughput capacity.¹⁹⁷

¹⁹¹ Tr. 5055-5059 (Hisey); MUN7-9023 at 209, 217, 239, 262.

¹⁹² Tr. 5055-5059 (Hisey); MUN7-9023 at 217, 262, 268, 343.

¹⁹³ Tr. 4957, 4970, 6444 (Hisey); MUN7-2069 at 262.

¹⁹⁴ Tr. 6445 (Hisey).

¹⁹⁵ Tr. 4983, 5053-54 (Hisey); MUN7-9023 at 37-38.

¹⁹⁶ Tr. 7061-62 (Ray).

¹⁹⁷ MUN7-9023 at 209, 217, 239, 262, 268, 343.

131. The evidence at trial demonstrated that the current mechanical capacity of TAPS is 760,000 bbl/d and that with DRA, TAPS is currently physically able to transport 1.1 million bbl/d.¹⁹⁸

132. In the Amended Capacity Settlement Agreement (“ACSA”), “TAPS Capacity” is a defined term that represents the “Pipeline’s capacity set forth on Exhibit C.”¹⁹⁹ In turn, “Exhibit C” sets forth the “TAPS Capacity Table” that establishes 1.1 million bbl/d as the “TAPS Capacity” after January 1, 2004 until the Agreement expires at the end of 2011.²⁰⁰ An Owner’s right to transport its percentage ownership share is based upon “Actual Daily Pipeline Capacity” which, in turn, is based upon “TAPS Capacity” as defined in “Exhibit C.”²⁰¹ Exhibit C indicates “All volumes are in barrels.”²⁰² The associated TAPS’ Operating Agreement specifies that a barrel is “42 U.S. standard gallons at 60° Fahrenheit.”²⁰³

133. The ACSA discussed “flow improvement” allocation as:

[T]he allocation among the Owners of flow improvement that exceeds TAPS Capacity, whether achieved through the use of a drag reducing agent or through other means; provided, however, that such flow improvement shall be exclusive of any Capacity Cushion and shall be allocated only to the extent that it exceeds TAPS Capacity²⁰⁴

The concepts of flow and “flow improvement” with respect to TAPS are concepts related to

¹⁹⁸ Tr. 7137-39 (Ray). This Court was unpersuaded by Mr. Ray’s testimony that TAPS’ current capacity is only 870,000 bbl/d because the Owners would need to spend approximately two million dollars to upgrade DRA injection sites before TAPS could carry 1.1 million bbl/d. See Tr. 7049-51 (Ray).

¹⁹⁹ MUN7-0215 at 213.

²⁰⁰ MUN7-0215 at 225.

²⁰¹ MUN7-0215 at 213.

²⁰² MUN7-0215 at 225.

²⁰³ TO-07-0179.0218.

²⁰⁴ MUN7-0215 at 214-15.

the flow of oil²⁰⁵ – which is related to physical capacity, not nominating capacity.

134. This Court finds that as between the Owners, a primary function of the ACSA was to resolve the nominating dispute among them. But the State was also a party to the agreement. Upon consideration of all the evidence, this Court is not persuaded by the Owners' assertion that the ACSA should be read to concern only a nomination process. A right to transport up to an ownership percent of 1.1 million bbl/d would have little meaning without the actual ability to transport those same barrels.

135. The Owners assert that the ACSA could only address nominating issues because FERC approved the ACSA pursuant to § 5(1) of the Interstate Commerce Act, and “Section 5(1) of the ICA applies to the ACSA only to the extent the ACSA provides for a ‘pooling’ arrangement that allocates pipeline capacity on a basis other than each TAPS Owner’s percentage ownership share.”²⁰⁶ Yet the FERC order approving the ACSA does not expressly deem the agreement to constitute a pooling arrangement; rather, FERC stated it is approved “even if the Amended CSA is deemed to be a pool.”²⁰⁷

136. The Owners' current reading of the ACSA is similar, if not identical, to the “mechanical capacity” position of certain of the Owners that was compromised away when all Owners reached agreement through the ACSA. The “mechanical capacity” position was that each Owner could only transport its ownership share of TAPS' current mechanical capacity.²⁰⁸

²⁰⁵ Tr. 7080-81 (Ray).

²⁰⁶ Owners' Proposed Findings of Fact and Conclusions of Law ¶ 631.

²⁰⁷ TO-07-0190.0008. In the FERC order approving the ACSA, the Commission also stated, “We concluded that the [TAPS] Quality Bank agreement was no more a pool than the joint operation of TAPS itself. We believe that the same reasoning is applicable to the Amended CSA.” TO-07-0190.0007.

²⁰⁸ Tr. 7062-63 (Ray).

137. The conduct of the Owners after execution of the ACSA further demonstrates that the parties intended for TAPS to have a physical capacity of 1.1 million bbl/d (with 1.14 million bbl/d capacity for winter flow rates). As held by the Alaska Supreme Court, the parties' conduct after entering into a contract is probative of intent. Conduct is a better indicator of intent than is testimony.²⁰⁹ The Owners used a design basis for the SR project from 300,000 to 1.14 million bbl/d with upward scalability to 2.1 million bbl/d.²¹⁰ The SR project is not yet complete, but the Owners plan to complete it.²¹¹ The Court finds that the Owners would not continue to spend over \$700 million on SR to provide a capacity to transport up to 1.14 million bbl/d with upward scalability to 2.1 million bbl/d if such capacity and upward scalability were neither required nor desirable. The Alaska Supreme Court has held that "evidence that both parties made substantial investments in the plant supports a conclusion they each intended to retain the items in which they invested[.]"²¹²

138. Also instructive to this Court were the Owners' representations to the RCA when seeking to abandon pump stations as part of their SR efforts. In that process, the Owners made a verified representation to the RCA:

After completion of [Strategic Reconfiguration], TAPS will be able to transport up to 1.14 million barrels per day. Moreover, should there be any additional oil fields brought on line that would cause throughput to exceed the 1.14 million barrels per day figure, the design of the remaining TAPS pump stations will be modular and

²⁰⁹ *North Pac. Processors, Inc. v. City and Borough of Yakutat*, 113 P 3d 575, 585 (Alaska 2005). See also *Peterson v. Wirum*, 625 P2d. 866, 870 (Alaska 1981) (conduct during performance can be admissible extrinsic evidence but opinions expressed during litigation regarding parties' intent do not establish an issue of fact regarding the parties' reasonable expectations at the time they entered into the contract).

²¹⁰ Tr. 9198-99 (Malvick).

²¹¹ Tr. 7140 (Ray).

²¹² *North Pac. Processors*, 112 P.3d at 585 (citations omitted).

will allow current and increased throughput capability within 36 months by the addition of modular units[.]²¹³

139. AS 42.06.290(a) states that “[a] pipeline carrier may not abandon or permanently discontinue use of all or any portion of a pipeline or abandon or discontinue any service rendered by means of a pipeline . . . without the permission and approval of the commission[.]” Such approval may only occur “after due notice and hearing, and a finding by the commission that continued service is not required by public convenience and necessity.”²¹⁴

140. The RCA granted the Owners the right to abandon several pump stations based upon the representations of the Owners that they would maintain the capacity to transport 1.14 million bbl/d²¹⁵ and their representation “that should North Slope production ever exceed the 1.14 million barrels per day, the design of the remaining operating pump stations will allow for increased throughput capability within 36 months by adding modular units to those pump stations.”²¹⁶ The RCA order also noted that the TAPS Owners had represented that the abandonment of those several pump stations “will not interfere with the TAPS’ ability to accommodate current or future throughput requirements, and will have no impact on the stipulated capacity requirements under the Amended Capacity Settlement Agreement.”²¹⁷ In a footnote, the RCA noted that the “TAPS carriers stated that the Amended Capacity Settlement Agreement provides a stipulated aggregate capacity of 1.1

²¹³ MUN7-0218 at 19, 22.

²¹⁴ AS 42.06.290(a).

²¹⁵ MUN7-0219 at 11. Although this exhibit was not admitted into evidence, the Court has taken judicial notice of this RCA Order P-04-21 dated April 6, 2005.

²¹⁶ MUN7-0219 at 11.

²¹⁷ MUN7-0219 at 12-13.

million barrels per day for the years 2004 forward.”²¹⁸ The Court finds that the Owners’ representations to the RCA are consistent with this Court’s reading of DB-180 and the ACSA. In the 2010 Amended Decision, this Court interpreted the ACSA to require the Owners to maintain a physical capacity of 1.1 million bbl/d. This Court again finds that the weight of the evidence presented at the trial of the 2007 through 2009 tax years supports that contractual interpretation of the ACSA. During the lien years the Owners had a legal duty to maintain TAPS’ physical capacity to transport up to 1.1 million bbl/d with upward scalability should new fields be developed.

VI. CHOICE OF VALUATION METHOD

141. All parties agree and every appraiser testified that in appraising a property, appraisers typically consider three generally recognized approaches to value: the cost approach, the income approach, and the comparable sales approach.²¹⁹ The cost approach is based upon a principle of substitution.²²⁰ This principle provides that a prudent buyer will not pay more for an existing property than the cost of acquiring a substitute property of equivalent utility.²²¹ The principle of substitution assumes replaceability without undue delay.²²² Under the income approach, “value is indicated by a property’s earning power, based on the capitalization of income.”²²³ Under the comparable sales approach, “value is indicated by recent sales of comparable properties in the market and other supporting

²¹⁸ MUN7-0219 at 13, n. 41.

²¹⁹ Tr. 11766, 11966 (Remsha); Tr. 11229, 11238-39 (Podwalny); 1020 (Connolly).

²²⁰ Tr. 1153-54, 1157-58 (Hoffbeck).

²²¹ *The Appraisal of Real Estate* at 38-39.

²²² *The Appraisal of Real Estate* at 380.

²²³ *The Appraisal of Real Estate* at 130.

transactional information.”²²⁴ All parties fully litigated the issue of whether the cost, income, and sales comparison approaches are reliable indicators of value for TAPS in the 2007, 2008, and 2009 trial de novo.

142. The applicable statute and regulation require an assessment that captures the “economic value” of TAPS within the context of the ANS proven reserves. TAPS’ economic value derives from its use in providing primarily affiliated transportation and market access for an entire oil region. Since 2005 through the lien years at issue, SARB has repeatedly held that the cost approach best captures the full economic value of TAPS consistent with AS 43.56.060(e)(2).²²⁵

143. The unique nature of TAPS as a limited-market and special-purpose property supports SARB’s use of the cost approach as the only reliable indicator of value.²²⁶ TAPS was specifically designed, constructed, and adapted to its particular use – to move affiliated ANS crude oil from the North Slope to Valdez.²²⁷ A property with this unique function is properly valued under the cost approach.

144. Owners’ expert Roger Marks recognized that if the tariffs are zero, it would be appropriate to value TAPS using the cost approach.²²⁸ Mr. Marks also acknowledged that the Owners would probably operate TAPS even if it had no tariff income.²²⁹

145. The cost approach is particularly reliable when a property is first built or when

²²⁴ *The Appraisal of Real Estate* at 130.

²²⁵ See, e.g. MUN7-0236 at 8-32.

²²⁶ Tr. 11355-56 (Podwalny); Tr. 11903 (Remsha).

²²⁷ Tr. 8196 (Cicchetti); MUN7-0001 at 3767 (Coulson Dep.).

²²⁸ Tr. 7852-55 (Marks).

²²⁹ Tr. 12170 (Marks).

it undergoes a substantial renovation.²³⁰ At the time of the 2007, 2008, and 2009 valuations of TAPS, the \$700 million SR project was underway to upgrade TAPS.²³¹

146. The extensive cost studies presented by both the Municipalities and Owners further support reliance on the cost approach.

147. An income approach based solely upon tariff income is not reliable for valuing an integrated, special-purpose property that has been adapted to a specific use for which the income stream is not the economic driver or basis for the property's construction and continued use.²³²

148. In its 2009 Decision, SARB explained its rejection of the tariff-based income approach as follows:

The fact that the TAPS produces a tariff income in addition to transporting oil would not justify reliance on an income approach, as opposed to the generally applied cost approach, because oil transportation, not the TAPS tariff income stream, is the motivation for ownership of the TAPS.²³³

149. The sales comparison approach is generally not reliable for valuing limited-market properties or special-purpose properties such as TAPS when there are no comparable sales, or when the sales that do exist are not comparable because the subject property has been adapted to a particular use at a particular location.²³⁴

²³⁰ Tr. 11994 (Remsha).

²³¹ Tr. 7140 (Ray).

²³² Tr. 12348 (Connolly); Amended Decision ¶ 120.

²³³ MUN7-0236 at 30.

²³⁴ *Fed. Reserve Bank of Minneapolis v. State*, 313 N.W.2d 619, 622-624 (Minn. 1981); MUN7-0234 at 17 (2007 SARB); MUN7-0236 at 30 (2009 SARB); *Valuing Machinery and Equipment* at 6.

150. In addition, the sales comparison approach is not generally used for valuing properties that are integrated with other properties because each sale has to be substantially adjusted to reflect only the portion of the integrated enterprise being valued.²³⁵

151. The standard treatise for machinery and technical specialties (“MTS”) states:

The income approach to value is not widely used today by most MTS appraisers; the reasons given include the difficulty in determining income that can be directly related to a specific asset, the concern over the reliability of income forecasts, and the multitude of variables involved in this valuation approach. . . . The sales comparison approach is not feasible when the subject property is unique.²³⁶

152. Other courts have similarly held that regulated pipelines should not be valued for ad valorem purposes under either the income or comparable sales approach.²³⁷

153. The Division and SARB considered all three of the primary approaches to valuation before determining that the Replacement Cost New Less Depreciation (“RCNLD”) approach was appropriate.²³⁸ Based upon the evidence presented at the trial de novo, this Court finds that reliance on the cost approach is appropriate to determine the “full and true” value of TAPS for 2007, 2008, and 2009.

\\
\\
\\
\\

²³⁵ TO-07-0004.0087 (American Appraisal). In the case of TAPS, every sale of an interest in TAPS has been part of a larger integrated transaction.

²³⁶ *Valuing Machinery and Equipment* at 122, 159-60.

²³⁷ *Transcontinental Gas Pipeline Corp.*, 545 A.2d at 746; *Tenneco*, 104 A.D.2d at 514; *Matter of Onondaga County Water Dist. v. Bd. of Assessors of Town of Minetto*, 350 N.E.2d 390, 392 (N.Y. 1976); *Tex E. Transmission Corp. v. E. Amwell Twp.*, 13 N.J. Tax 24, 28-29 (N.J. Tax Ct. 1992); Amended Decision ¶ 12.

²³⁸ MUN7-0234 at 2, 13, 16-17; MUN7-0235 at 2, 15-16; MUN7-0236 at 2, 27-32.

VII. THE COST APPROACH

154. There are three starting points for the application of the cost approach: original cost, reproduction cost, or replacement cost.²³⁹ The use of original cost, either in nominal dollars or indexed to current dollars, is a limited but useful indicator of the cost to build TAPS today. TAPS cost approximately \$8 billion to build in 1977 dollars – an amount that the Division calculated as equal to \$23.4 billion for 2009 based upon trending the original cost using Marshall & Swift.²⁴⁰ SARB noted the \$19.8 billion Pro Plus RCN compared favorably to the original trended cost for that lien year.²⁴¹

155. Reliance on a trended original cost as the basis for valuing TAPS is not warranted because TAPS' original design has been substantially updated and a trended original cost would not capture the value of the asset in place as of the lien dates.

156. A reproduction cost is the cost to replicate an exact duplicate or replica of what is in place, which could include substantial obsolescence.²⁴²

157. A replacement cost analysis replaces TAPS' current equivalent utility based on modern design, materials, and construction techniques.²⁴³ The Owners and the Municipalities both presented replacement cost new ("RCN") estimates to the Board and to this Court in the de novo trial, although as discussed herein the Municipalities' RCN was far more similar to the existing TAPS than the RCN presented by the Owners.

²³⁹ *The Appraisal of Real Estate* at 378.

²⁴⁰ MUN7-0236 at 31 n. 10 (SARB 2009 Decision).

²⁴¹ MUN7-0236 at 31 n. 10 (SARB 2009 Decision).

²⁴² *The Appraisal of Real Estate* at 385.

²⁴³ *The Appraisal of Real Estate* at 385-86; Tr. 580 (Remsha).

A. Replacement Cost New

158. RCN is “the current cost of a similar new property having the nearest equivalent utility as the property being appraised, as of a specific date.”²⁴⁴ It has also been defined as “the estimated cost to construct, as of the effective date, a substitute for the [property] being appraised using contemporary materials, standards, design, and layout.”²⁴⁵

159. In an *Appraisal Journal* article titled *Replacement of What?* that was relied upon by Mr. Hoffbeck at trial, Donald Treadwell opined that:

The selection of an appropriate replacement model in the cost approach is critical to the appraisal. The use of a replacement model that is significantly different from the subject may challenge implicit assumptions concerning the extent of functional and economic obsolescence incurred by components of the subject.²⁴⁶

160. RCN estimates fall along a continuum from a complete redesign to a near reproduction.²⁴⁷ This Court finds that the concerns raised in the Treadwell article and discussed by Mr. Hoffbeck in the context of the historical examples of redesign persuasively demonstrate why it is important to use the correct replacement property and then adjust the RCN using the tools set out in the appraisal literature such as functional and economic obsolescence adjustments to arrive at the value of the subject property.

161. This Court finds that the evidence does not support the Assessor’s apparent assertion that at least some components of the Pro Plus estimate may be reproduction estimates. Rather, the Pro Plus estimate replaced the utility of TAPS, but utilized modern and current design, materials and construction techniques in its design, work plan, and

²⁴⁴ *Valuing Machinery and Equipment* at 186; Tr. 580 (Remsha).

²⁴⁵ *The Appraisal of Real Estate* at 385.

²⁴⁶ MUN7-0046 at 25; Tr. 1056 (Hoffbeck).

²⁴⁷ Tr. 12773 (Greeley).

estimate. And, as further discussed herein, the Assessor's placement of the Stantec design as somewhere in the middle of the continuum between a redesign and a reproduction is not supported by the evidence.

1. A Summary of the Cost Studies

162. In 2007, SARB relied on Mustang Engineering's 2006 RCN trended forward one year, which estimated a replacement cost of \$8,276,423,150.²⁴⁸ At the de novo trial, no party supported the Mustang cost study.

163. Before SARB in 2007, the Owners also presented evidence on a 30-inch pipeline study prepared by Mustang.²⁴⁹ The conceptual design basis assumptions included: 850,000 bbl/d maximum flow with the use of DRA, X-100 pipe, and seven pump stations.²⁵⁰ SARB did not rely upon this 30-inch pipeline study in its 2007 decision.²⁵¹

164. In 2008, the Municipalities first presented the Pro Plus study to SARB.²⁵² The Department and the Board relied upon the Pro Plus RCN cost estimate of \$17.02 billion.²⁵³ For that year, Pro Plus adjusted the original cost of the VMT for superadequacy, inflation-trended the revised cost, and accepted Mustang's numbers for several items that they had insufficient information to independently estimate.²⁵⁴ The estimate was made before any significant discovery had been obtained by the Municipalities.

²⁴⁸ MUN7-0234 at 12.

²⁴⁹ 2007 R. 13059-84.

²⁵⁰ 2007 R. 13059-84.

²⁵¹ 2007 R. 584-98 (MUN7-0234 at 11-24).

²⁵² MUN7-0235 at 15.

²⁵³ 2008 R. 11515-11825.

²⁵⁴ MUN7-0235 at 15.

165. By 2009, Pro Plus had received new information from discovery in the 2006 de novo tax case and had added the expertise of an engineering firm specializing in marine terminals. Before SARB, Pro Plus estimated the RCN of the entire system, including the VMT, at \$21.1 billion in 2009.²⁵⁵ After some adjustment, SARB found that the RCN was \$19.805 billion.²⁵⁶

166. Also before the Board in 2009 was a hydraulic analysis conducted by Mustang Engineering on behalf of the Owners.²⁵⁷ The hydraulic analysis assumed a 42-inch pipeline from Prudhoe Bay to Valdez at “the current flow rate of 1 million bbl/d.”²⁵⁸ Mustang concluded that “[t]o obtain a flow rate of 1 MMBOPD [million bbl/d], the 42-inch system requires a full complement of 12 pump stations. There is virtually no capacity over 1 million bbl/d in the 42-inch pipeline.”²⁵⁹ Mustang also conducted a cost analysis between the 42-inch and 48-inch line and concluded that

[w]hen comparing the base 48” system with a potential 42” system, the 42” system would require an approximate increase in investment, due to the higher horsepower requirements, of \$275MM and an approximate decrease due to saving pipe material and installation costs of \$150MM. The net investment cost difference is an increase of \$125MM for installation of a 42” line versus a 48” line. This rough estimate does not include the additional operating costs for 12 pump stations, as opposed to 6, or spare parts costs (included in the program management fees).²⁶⁰

²⁵⁵ 2009 R. 16-67.

²⁵⁶ MUN7-0236 at 18.

²⁵⁷ 2009 R. 10341-46; Tr. 6870-71 (Greeley).

²⁵⁸ 2009 R. 10343.

²⁵⁹ 2009 R. 10345.

²⁶⁰ 2009 R. 10345.

167. In evaluating the Stantec 30-inch pipeline, this Court has accorded some weight to the opinion of the Owners' experts in 2009 before SARB that a 42-inch pipeline was inadequate to transport throughput of over 1 million bbl/d.

168. The Owners first presented the Stantec cost study to SARB in 2010. The Owners presented a similar Stantec cost study to SARB in 2011.

169. In both 2010 and 2011, SARB held that reliance on the Stantec 30-inch pipeline for valuing TAPS "would have been improper" because "costing a hypothetical property that is so different from the existing property, to measure obsolescence, is an extreme and inappropriate use of this appraisal technique."²⁶¹

170. In its Amended Decision, this Court relied upon the Pro Plus RCN and found that as of January 1, 2006, a replacement pipeline with utility equivalent to TAPS would cost approximately \$18 billion to replace.²⁶²

171. At the trial de novo before this Court for the current tax years, the Municipalities presented the Pro Plus cost studies which estimated the cost to replace TAPS' equivalent utility in 2007 at \$19.606 billion, in 2008 at \$21.471 billion, and in 2009 at \$21.263 billion.²⁶³ The Owners presented the Stantec cost studies estimating the cost to replace TAPS with a 30-inch pipeline at \$9.352 billion in 2007, \$9.702 billion in 2008, and \$9.721 billion in 2009.²⁶⁴

²⁶¹ See MUN7-0238 at 30-31.

²⁶² Amended Decision ¶ 511.

²⁶³ Tr. 3787 (Ellwood); MUN7-0008 at 1627-1628.

²⁶⁴ TO-07-0021 at 8; TO-07-0023 at 8; TO-07-0025 at 8. The Stantec figures do not include interest during construction and ad valorem taxes, which were computed by American Appraisal.

172. Pro Plus used a design criteria of 1.1 million bbl/d maximum throughput for all three lien years with a 48-inch diameter pipe size.²⁶⁵

173. Stantec used a 30-inch pipeline with a design basis of 900,000 bbl/d for 2007, 800,000 bbl/d for 2008, and 750,000 bbl/d for 2009.²⁶⁶

174. The following chart compares some of the design parameters of the existing TAPS, the Pro Plus RCN, and the Stantec RCN:

	<u>TAPS</u>	<u>Pro Plus RCN</u>	<u>Stantec RCN</u>
Diameter:	48"	48"	30"
Maximum Capacity of Mainline Pipe:	2.1 million bbl/d	2.1 million bbl/d	Unknown – no more than 1.1 million bbl/d
Maximum Pressure:	1,180 psi	1,180 psi	2,158 psi
Velocity at 1.1 million bbl/d:	10 ft/s	10 ft/s	15 ft/s
Number of Miles Aboveground:	420	420	629
Vertical Support Members:	Dual-pile	Dual-pile	Mono-pile
Thermosyphons:	Inside VSMs	Inside VSMs	Freestanding
Aboveground Pipe Support Spacing:	60 ft.	60 ft.	90 ft.

²⁶⁵ Tr. 3716 (Ellwood); Tr. 4460 (Steindorff).

²⁶⁶ Tr. 4472 (Steindorff); TO-07-00021 at 7; TO-07-00023 at 7; TO-07-00025 at 7.

2. The Stantec Hypothetical Pipeline Is Not an Acceptable Comparison Property to TAPS for Ad Valorem Tax Purposes

175. The parties extensively litigated whether this Court should adopt the Stantec 30-inch pipeline or the Pro Plus 48-inch pipeline as the basis for the RCN calculation for the 2007, 2008, and 2009 tax years. The Municipalities presented evidence and argued that the Stantec 30-inch pipeline is too different from the existing TAPS such that it cannot provide a reasonable basis for determining the full and true value of TAPS. They further argued that the Stantec 30-inch pipeline is premised on an inappropriate appraisal technique and as a practical matter, it will not be able to operate within reasonable design parameters.

176. The Owners presented extensive engineering testimony in support of the Stantec RCN. They also rely on Mr. Hisey and Mr. Greeley's testimony to support their 30-inch pipeline design. Mr. Hisey testified that a 48-inch pipeline would likely not be the optimal design for a new pipeline if TAPS' throughput was projected not to exceed 900,000 or 700,000 bbl/d. But Mr. Hisey also testified that the optimal size for a pipeline that would be similar to and have the same utility as the existing TAPS would be a 48-inch pipeline. In that regard, he stated "the 30-inch design would not be the right design for any of the operating years . . . in question, 2007, 2008, and 2009 . . . I cannot assess how you call it a similar design to the existing facility; no, it's not similar at all."²⁶⁷

177. Although it appeared that the Assessor Mr. Greeley testified that he would choose the Stantec RCN over the Pro Plus RCN, the Department's counsel stated in closing that Mr. Greeley was not choosing between the two cost studies.²⁶⁸ Regardless, this Court

²⁶⁷ Tr. 5052, 6457-58 (Hisey).

²⁶⁸ Tr. 6809 (Greeley); 8461 (Johnson).

gives little weight to Mr. Greeley's testimony regarding the Stantec cost study since he demonstrated a lack of knowledge about key components of that study.²⁶⁹

178. None of the approximately twenty experts testifying in the RCN section of this case could identify a single crude oil pipeline that had been built with each of the characteristics of Stantec's 30-inch pipeline design.

179. Mr. Hoffbeck identified certain criteria to determine whether a proposed replacement property should be used as the starting point in a cost approach, which this Court has found helpful to consider:

- a. whether there are legal restrictions that would make the proposed property unacceptable, and if so whether there is a likelihood they can be removed;
- b. whether the proposed replacement property is of similar quality and like utility to the subject property;
- c. whether the replacement property is an appropriate application of appraisal theory for use in the assessment process;
- d. whether the design will operate as specified;
- e. whether the design captures all direct and indirect costs associated with the construction of the replacement property, and if not, whether the estimate can be adjusted to reflect all of those costs; and
- f. whether the replacement property is similar enough to the subject property to permit the accurate identification and quantification of obsolescence.²⁷⁰

²⁶⁹ For example, Mr. Greeley was unable to answer questions regarding the amount of horsepower required for the pumps in Stantec's cost study, or whether all three trains of pumps need to be running at 1.1 million bbl/d. Tr. 6962-6970 (Greeley). In addition, Mr. Greeley testified that he "looked at the equipment rates that were used for the construction of the Valdez Marine Terminal;" however, Stantec did not determine equipment rates, but rather its equipment costs are based on a percentage of direct labor. *Compare* Tr. 13000-13003 (Greeley) *with* Tr. 2496-97 (Rein).

²⁷⁰ Tr. 11523-11554 (Hoffbeck).

a. Legal Restrictions

180. The TAPS Owners have committed to the RCA to maintain and expand TAPS' existing capacity if needed in the future. The Stantec design is inconsistent with these commitments and resultant RCA order and would require RCA approval.²⁷¹ This Court finds such approval improbable. The RCA would have to determine that the abandonment of TAPS' current 1.1 million bbl/d capacity and its upward scalability above that throughput is in the public interest – a finding likely to be challenged by existing and future stakeholders seeking to expand and optimize Alaska North Slope development.²⁷²

181. The Stantec RCN pipeline also does not meet the design specifications for the existing property as found in Alyeska's DB-180.²⁷³ The DB-180 under the Design Criteria Section 4.3.2 specifies that:

TAPS is designed to transport crude oil from Prudhoe Bay to Valdez, Alaska. Throughput range for the system is .3 to 2.1 MMSBPD [million bbl/d] under steady conditions of operations, although it should be noted that this may require installation of short term DRA injection facilities at various locations to reach the high end of this range.²⁷⁴

The General Hydraulic Criteria and Considerations Section of DB-180 states:

[t]he mainline and facilities of the trans-Alaska pipeline system shall be designed to transport crude oil or other hydrocarbons from Prudhoe Bay, Alaska at nominal rates to Valdez, Alaska between 0.3 to 2.1 MMSBPD [million bbl/d]. Hydraulic design criteria shall apply to the mainline, mainline facilities, and connection facilities throughout this range of design mainline unless otherwise specified.²⁷⁵

²⁷¹ AS 42.06.290(a).

²⁷² Tr. 11526 (Hoffbeck).

²⁷³ Tr. 4466 (Steindoff); Tr. 5170 (Riordan); Tr. 3391-92 (Annett).

²⁷⁴ MUN7-9023 at 209; Tr. 4956, 4985, 4989-90, 5055-56, 6445 (Hisey).

²⁷⁵ MUN7-9023 at 217; Tr. 5056-19 (Hisey).

DB-180 also states that, “[t]he mainline pumps at the designated pump stations are required to pump from 0.3 to 2.1 MMSBPD [million bbl/d].”²⁷⁶ The piping systems are also “maintained to sustain maximum operating conditions up to 2.1 million barrels per day under all operating conditions allowed per 49 CFR 195, *Transportation: Transportation of Hazardous Liquids by Pipeline*.”²⁷⁷ Although TAPS cannot currently transport 2.1 million bbl/d, if the pump stations that have been ramped down are brought back on line and DRA injection sites upgraded, then TAPS can transport 2.1 million bbl/d.

182. While Mr. Riordan of Alyeska suggested that DB-180 could be unilaterally changed by the Owners without following the formal process outlined in the DB-180, the evidence at trial persuaded the Court otherwise.²⁷⁸ The DB-180 clearly provides that the Joint Pipeline Office (“JPO”) must approve any change or variance of the TAPS design basis criteria set forth in DB-180.²⁷⁹ And while Mr. Hisey, former Chief Operating Officer for Alyeska, acknowledges that editorial changes, such as naming buildings, are made to the DB-180 without regulatory approval, he could not recall any specific change to the DB-180 related to capacity or throughput that was made without regulatory approval.²⁸⁰

183. Further, as discussed above, this Court has again concluded that the Amended Capacity Settlement Agreement required the TAPS Owners to maintain at least 1.1 million bbl/d capacity during the lien years.

²⁷⁶ MUN7-9023 at 239; Tr. 4989-4990, 5057 (Hisey).

²⁷⁷ MUN7-9023 at 352; Tr. 5058 (Hisey).

²⁷⁸ Tr. 5173-5174 (Riordan); Tr. 6448-49 (Hisey); Tr. 3392 (Annett); MUN7-9023 at 37.

²⁷⁹ Tr. 5173 (Riordan); Tr. 4956, 4988, 5053-55, 5059, 6448-49 (Hisey). See also MUN7-9023 at 35, 37; Tr. 3392 (Annett) (discussing DB-180).

²⁸⁰ Tr. 4988-89 (Hisey).

184. The Owners failed to establish by a preponderance of the evidence that the existing RCA requirements and the DB-180 design basis would permit the Stantec 30-inch pipeline to be built as a replacement for TAPS.²⁸¹

b. The Stantec Design Is Not of Similar Quality and Like Utility

185. A replacement property should be “a similar new property having the nearest equivalent utility as the property being appraised.”²⁸²

186. Utility in the appraisal context is not necessarily limited to how the property is currently being used.²⁸³ The Owners’ lead appraiser, Mr. Remsha, acknowledged that a 30-inch pipeline and 48-inch pipeline have “quite different utility from each other.”²⁸⁴ “By definition, utility is any aspect of the property that would create a desire for ownership. It’s significantly different from the concept of usefulness, which is how it is currently being used.”²⁸⁵ Mr. Hoffbeck persuasively testified that TAPS’ utility is more than its ability to ship oil at the current throughput levels²⁸⁶ – it also includes TAPS’ flexibility and upward scalability.

187. TAPS is 48 inches in diameter; the Stantec RCN is 30 inches. Mr. Remsha indicated that he has never before used a different diameter replacement pipe than the subject property for an RCN.²⁸⁷

²⁸¹ Tr. 822 (Podwalny).

²⁸² *Valuing Machinery and Equipment* at 44.

²⁸³ Tr. 1060 (Hoffbeck).

²⁸⁴ Tr. 12502 (Remsha).

²⁸⁵ Tr. 1061 (Hoffbeck).

²⁸⁶ Tr. 11532 (Hoffbeck).

²⁸⁷ Tr. 579, 12506 (Remsha).

188. Mr. Remsha acknowledges that the design capacity for TAPS as of the lien dates was 1.42 million bbl/d.²⁸⁸ Yet American Appraisal based their RCN on a pipe that could not meet that design capacity of TAPS, no matter how much DRA is used.²⁸⁹

189. At Stantec's 1.1 million bbl/d case, the 30-inch pipeline will be operating over 15 feet per second ("ft/s").²⁹⁰ For Stantec's 2007 case, the velocity will be 12.7 ft/s; for the 2008 case, the velocity will be 11.3 ft/s; and for the 2009 case, the velocity will be 10.6 ft/s.²⁹¹

190. The current TAPS, as well as the Pro Plus RCN, will operate at velocities of less than 10 ft/s for throughputs of up to 1.1 million bbl/d.²⁹² In defending the high velocities in their design, Alyeska engineer Joe Riordan testified that TAPS' velocities "approach[ed] 12 feet per second" when throughput was at its very highest at 2.136 million bbl/d.²⁹³ However, TAPS was built with robust engineering to transport 2.1 million bbl/d at high velocities for temporary periods of time. In contrast, the Stantec design is built only to the minimum specifications necessary to transport the throughput for each of the lien years at issue. Moreover, at 2007 throughputs and at 1.1 million bbl/d, the Stantec RCN is designed to operate at velocities well above the maximum ever attained on TAPS' 48-inch mainline pipe.

²⁸⁸ Tr. 534, 12506-07 (Remsha).

²⁸⁹ Tr. 2086 (Pietsch).

²⁹⁰ Tr. 4489 (Steindorff) (relying on MUN7-1182).

²⁹¹ Tr. 4489, 4504-07 (Steindorff) (relying on MUN7-1182).

²⁹² Tr. 4489, 4506-07 (Steindorff).

²⁹³ Tr. 1594 (Riordan).

191. In comparing existing and planned pipelines ranging from 30 inches to 42 inches in diameter, the highest velocity is 7 ft/s.²⁹⁴ The evidence persuasively demonstrates that the high velocities in Stantec's RCN exceed industry standards for crude oil pipelines and may cause surge pressure issues.²⁹⁵

192. TAPS was constructed and is operated at typical pressures for North American pipelines. DB-180 requires that the TAPS' internal design pressure be between 700 psi and 1180 psi, depending on the grade of pipe.²⁹⁶ Similarly, Pro Plus's design operates at 1,180 psi.²⁹⁷

193. The Stantec 30-inch pipeline operates at far higher pressures than TAPS or a typical long-distance crude oil pipeline.²⁹⁸ Stantec's design operates at 2,158 psi – approximately twice the pressure of the existing TAPS.²⁹⁹

194. There is no evidence in the record of a long-distance crude oil pipeline operating at such high pressures in North America.³⁰⁰

²⁹⁴ Tr. 4489 (Steindorff) (relying on MUN7-1182).

²⁹⁵ Tr. 4489-90, 4504-07 (Steindorff) (relying on MUN7-1182). DB-180 requires that the surge pressure rises do not exceed the internal design pressure by more than 10%. MUN7-9023 at 156.

²⁹⁶ MUN7-9023 at 156, 174.

²⁹⁷ Tr. 4469 (Steindorff).

²⁹⁸ Tr. 3802-03 (Ellwood); Tr. 2032-34 (Pietsch); Tr. 2971-73 (Ziehr); Tr. 5152 (Riordan); Tr. 4469-70 (Steindorff); Tr. 4953-54 (Hisey); MUN7-0009 at 4-5; MUN7-0029.

²⁹⁹ Tr. 4469 (Steindorff).

³⁰⁰ Tr. 2035-36 (Pietsch) ("Q. Has any 30-inch high pressure crude oil pipeline ever been demonstrated to operate in the world? A. At what we designed the pressure? No."); Tr. 2032-34: 18 (Pietsch) ("Q. Are you aware of any cross-country crude oil pipeline that operate at over 2000 psi? A. No"; "Q. Are you aware of any long-distance cross-country crude oil pipeline that operates at 1500 psi? A. I'd say no"); Tr. 2972 (Ziehr) ("Q. In fact, you are not aware of any pipeline in the world that's a cross-country crude oil pipeline that operates 1400 psi, correct? A. Personally not aware of it, correct"); Tr. 2971 (Ziehr) (acknowledging that his company had never built a cross-country crude oil pipeline anywhere that operated above 1480 psi); Tr. 5152 (Riordan) ("Q. Have you ever done a project—a cross country pipeline project at these kinds of pressures in the past? A. No, sir"); Tr. 3116-17 (Meyer) ("Q. Are you aware of any ... long-distance crude oil pipeline in the world that operates above 1480? ... A. I am not.").

195. Through cross-examination of a Pro Plus expert, the Owners referred to one example of a high-pressured crude oil pipeline, the 30-inch Endymion. However, the Endymion is a 90-mile subsea pipeline that has an entirely different design related to the external water pressure on the underwater pipe.³⁰¹ This Court does not find this subsea pipeline to be similar to TAPS.

196. The operation of a pipeline at higher operating pressures is not as operationally or environmentally safe as the operation of a pipeline at lower operating pressures.³⁰² Operation at higher pressure also requires greater horsepower and has less of a safety margin than operation at lower pressures.³⁰³

197. The Stantec design does not have equivalent utility to TAPS with respect to operating pressure.

198. At any given throughput level a 30-inch pipeline will require more horsepower than a 48-inch pipeline due to frictional loss.³⁰⁴ For example, at a flow rate of 800,000 bbl/d, the 30-inch pipeline requires approximately 110,000 horsepower while the 48-inch pipeline requires approximately 58,000 horsepower.³⁰⁵

199. The Stantec 30-inch pipeline would require more DRA than a 48-inch pipe at any given throughput.³⁰⁶ Very large amounts of DRA are necessary to attempt to reach 1.1 million bbl/d throughput.³⁰⁷ This is substantially different from the existing TAPS.

³⁰¹ Tr. 3941-42 (Ellwood). Mr. Riordan acknowledged that the Endymion is not a cross-country pipeline. Tr. 5155 (Riordan).

³⁰² Tr. 4960-62 (Hisey).

³⁰³ Tr. 4958-59 (Hisey).

³⁰⁴ Tr. 5063 (Hisey); Tr. 3799-3800 (Ellwood); Tr. 4472-82 (Steindorff); Tr. 8123-28 (Modisette).

³⁰⁵ Tr. 4472-75 (Steindorff); MUN7-0008 at 24.

³⁰⁶ Tr. 5063 (Hisey).

200. The aboveground portions of TAPS' mainline pipe are supported on dual-pile vertical support members ("VSMs") with thermosyphons integrated into the design to maintain the appropriate ground temperature. VSMs are a unique method for supporting aboveground pipe in areas where there is concern that the warm crude oil pipeline would thaw the permafrost, causing settlement that may result in loss of support for the pipeline.³⁰⁸ Thermosyphons help maintain the tundra in a frozen state as necessary. The aboveground VSMs on TAPS are in a zig-zag pattern to accommodate pipe expansion and contraction, as well as seismic activity which they have successfully withstood.

201. Unlike TAPS, the aboveground portion of Stantec's 30-inch line is supported almost entirely by single or mono-pile VSMs.³⁰⁹ While there are mono-pile VSMs on the Alaska North Slope and at Valdez, the evidence persuasively demonstrates that mono-pile VSMs have never been proven to support long-distance crude oil transmission pipelines or pipelines in warm permafrost zones.³¹⁰

202. The mono-pile VSMs that have found limited use have not been integrated with thermosyphons to maintain ground temperatures.³¹¹ One of the Owners' experts, Mr. Carson, testified that he is unaware of the use of thermosyphons with mono-pile supports

³⁰⁷ MUN7-1553.

³⁰⁸ MUN7-0008 at 15.

³⁰⁹ TO-07-0021 at 10.

³¹⁰ Tr. 3115 (Meyer) ("Q. Are you familiar with any cross-country crude oil pipelines built on monopiles that ... has not been built into frozen ground. A. On monopiles, no, I am not. Q. Anywhere in the world today? A. I am not"); Tr. 4466 (Steindorff) ("The unproven technology and the application thereof is in the form of the mono-piles and the thermosyphons. We know of no long-distance, cross-country pipeline of any size that's on mono-piles. I don't think anybody's given us an example yet"); Tr. 4483-84 (Steindorff); Tr. 4973-74 (Hisey) (Stantec's mono-pile design has not been tested with the size of line and conditions that would be required for the 800 mile pipeline from Pump Station 1 to Valdez, unlike the original TAPS' VSM design which was subject to full scale testing for an extended period of time, to ensure adequate lateral support, so that if the pipeline moves, it will not affect the loading on the VSM"); Tr. 6454-66 (Hisey).

³¹¹ Tr. 3803-05, 3816-18 (Ellwood); Tr. 3202-03 (Carson).

anywhere in the world.³¹² He testified that he would do full scale testing of the technology for at least a season or two in the field before relying on it for a project like the replacement of TAPS.³¹³ Likewise, Mr. Ellwood testified that he knows thermosyphons work and he knows mono-piles work, but he has never seen this combination supporting a major oil pipeline in a warm permafrost region.³¹⁴ In addition, pipeline operations could be impacted because there is no mechanical protection for the freestanding thermosyphons in the Stantec RCN.³¹⁵

203. The thermosyphon study used in the Stantec replacement estimate was prepared by John Zarling, who was not a witness at trial.³¹⁶ Dr. Zarling's files were not provided to opposing counsel in discovery, nor had they been provided to the trial witnesses sponsoring the Stantec thermosyphons, Dr. Meyer and Mr. Carson of Michael Baker.³¹⁷ Thus, Mr. Carson could not tell the Court whether Dr. Zarling's analysis was correct,³¹⁸ and the Owners did not persuasively establish that the thermosyphon approach proposed for the Stantec 30-inch pipeline study is reliable.³¹⁹

204. This Court finds that Michael Baker's mono-pile VSM design at 90-foot spacing does not provide the same level of pipe support and redundancy as the existing dual-pile

³¹² Tr. 3210 (Carson).

³¹³ Tr. 3212 (Carson). *See also* Tr. 4973-75 (Hisey); Tr. 4466-68, 6614 (Steindorff).

³¹⁴ Tr. 3804, 6649-52 (Ellwood).

³¹⁵ Tr. 3819-20 (Ellwood).

³¹⁶ Tr. 3200-02 (Carson); Tr. 3112-23 (Meyer).

³¹⁷ Tr. 3200-01 (Carson).

³¹⁸ Tr. 3209 (Carson).

³¹⁹ Tr. 3200-3202 (Carson).

supports at 60-foot spacing on TAPS.³²⁰ Evidence was presented that the smaller the diameter of the pipe, the closer the necessary spacing becomes.³²¹ And yet Stantec has proposed to increase the spacing from 60 feet to 90 feet for its 30-inch pipeline. The Owners' experts, Dr. Meyer and Mr. Carson, testified that if two adjacent supports failed, the Stantec pipeline would touch the ground.³²² Dr. Meyer acknowledged that the existing TAPS design requires that the pipe remains suspended in the event of two adjoining VSM failures.³²³

205. The Stantec pipeline design work by Michael Baker also deviates from DB-180 for geometry changes, wind loading, and temperature differentials.³²⁴

206. Over two hundred more miles of the Stantec 30-inch pipeline are aboveground and supported by VSMs than on the current TAPS.³²⁵ The evidence persuasively showed that there are more safety risks and reliability issues for an aboveground pipeline.³²⁶

207. The decision to build the majority of the pipeline aboveground was not made by the Owners' structural engineer experts (Dr. Meyer and Mr. Carson) who were hired to design the VSMs, but rather by the Owners' hydraulics expert, Mr. Pietsch.³²⁷ Dr. Meyer and Mr. Carson were told that the majority of the pipeline needed to be built aboveground so as to aid Mr. Pietsch's hydraulics and heat transfer.³²⁸

³²⁰ Tr. 4466, 4484 (Steindorff); Tr. 3128 (Meyer).

³²¹ Tr. 4484, 4487-88 (Steindorff) (discussing MUN7-1167 at 2).

³²² Tr. 3129 (Meyer); Tr. 3204 (Carson).

³²³ Tr. 3128 (Meyer).

³²⁴ Tr. 3121-22, 3123, 3125-26 (Meyer). Compare TO-07-0013 at 17 with MUN7-9023 at 173-174.

³²⁵ Tr. 3198 (Carson); TO-07-0021 at 10 (stating "[m]ajor portions (approximately 629 miles) of the pipeline are constructed aboveground using Vertical Support Members (VSM)"). Cf. MUN7-0001 at 490.

³²⁶ Tr. 3801 (Ellwood).

³²⁷ Tr. 3118 (Meyer).

208. Michael Baker's report "Aboveground Pipeline Verification" provides several pipe configurations, including 90-degree bends. These bends are needed in the Stantec design to take up the growth/shrinkage of the pipeline as it expands and contracts with changes in temperature.³²⁹

209. Mr. Pietsch indicated that he did not account for the 90-degree bends in his simulations and acknowledged that the use of 90-degree bends would affect the simulation results since every bend carries a pressure drop in the oil.³³⁰

210. For the foregoing reasons, this Court finds that the Stantec pipeline, including the mono-pile VSMs and thermosyphon design, is of lower or lesser quality than the current design on TAPS.

211. A work pad is an area built up with additional fill and stabilized to provide a site on which to perform work.³³¹ Pro Plus and Stantec disagree on whether gravel or ice should be utilized for the work pad on that portion of the right-of-way located north of the Brooks Range.³³²

212. Use of ice pads could complicate the construction of a new pipeline, as it would eliminate the ability to perform any construction during a significant portion of the year where neither ice nor snow would be available to construct roads or pads.³³³

³²⁸ Tr. 3118-19 (Meyer). Mr. Rein, the primary witness on the Stantec RCN, testified that he was unaware that Mr. Pietsch had decided the percentage of the Stantec pipeline that would be aboveground. Tr. 5304 (Rein).

³²⁹ TO-07-013 at 12-14.

³³⁰ Tr. 2030-32 (Pietsch); Tr. 6668 (Ellwood).

³³¹ Tr. 3862 (Ellwood); MUN7-0008 at 7.

³³² Compare MUN7-0008 at 14 with TO-07-0021 at 21.

³³³ Tr. 6484 (Tise).

213. The continuing utility of an ice pad is far less than the utility of a granular work pad. Alyeska has continued to maintain the gravel work pad for over 30 years for contingency purposes and for oil spill response. It is also useful to deploy personnel, heavy equipment, and materials for maintenance purposes.³³⁴

214. The fact that Stantec will not have a granular work pad adjacent to all of the 800-mile pipeline means that the Stantec RCN is of lesser utility than TAPS in this regard.

215. In the Keystone Canyon area, Michael Baker selected a different route for the Stantec RCN from the current route, placing the 30-inch pipeline along the highway. Although this new route could cause disruptions to the community and traffic and safety issues for the public during construction,³³⁵ this Court finds that the Stantec proposed re-route would provide the same or similar utility as the current TAPS route.

216. Dr. Hite, an expert witness for the Municipalities, persuasively testified that large quantities of technically and economically recoverable oil exist in the Beaufort and Chukchi Seas, the Alaska National Wildlife Refuge, the National Petroleum Reserve Alaska, and the Central North Slope. Dr. Hite cited to a number of sources to support his testimony, including a federal evaluation and assessment of oil resources in Arctic Alaska that estimates there are potentially 30.85 billion barrels of economically recoverable oil available for shipment down TAPS.³³⁶

³³⁴ Tr. 1243-45 (Baldrige).

³³⁵ Tr. 5797 (Karlik); Tr. 3860-62 (Ellwood); Tr. 4165 (Tise); Tr. 4471-72 (Steindorff).

³³⁶ Tr. 9613-26 (Hite); MUN7-001 at 4226.

217. Dr. Hite persuasively testified that if production within the National Petroleum Reserve-Alaska, the Chukchi Sea, and the Beaufort Sea were brought online, ANS production could total 1.5 million bbl/d.³³⁷

218. Although the potential recoverable oil reserves identified by Dr. Hite are not proven reserves, Dr. Hite's testimony is relevant in determining TAPS' utility and what constitutes an appropriate replacement property that is reflective of TAPS' utility. This is best reflected by the fact that the TAPS Owners are maintaining upward scalability of TAPS so as to be able to transport increased throughputs.

219. Stantec's pump station design is based on the assumption that the throughput rates during the lien years are the maximum throughputs.³³⁸ The Owners' hydraulics expert Mr. Pietsch indicated that his 1.1 million bbl/d simulations for the Stantec RCN "were not the design plan rates. They were what I would call a maximum capacity test."³³⁹ Mr. Pietsch added, "To me, maximum capacity is the highest...the system can flow at."³⁴⁰

220. Mr. Pietsch also performed a tank utilization study for the VMT, but testified that the maximum volume he used to determine tank utilization was 739,000 bbl/d.³⁴¹

221. This Court finds that for the purposes of determining TAPS' value under the RCNLD method, a proposed replacement pipeline (before depreciation) must have an upward and downward flexibility to transport levels of throughput that is similar to the existing pipeline. Stantec's design significantly narrows the broad range of operating

³³⁷ Tr. 9629-31(Hite).

³³⁸ Tr. 5317 (Pietsch) (Stantec pipeline could not transport 2.1 million bbl/d; "It is designed for the throughputs that are used for each tax year.")

³³⁹ Tr. 1957 (Pietsch).

³⁴⁰ Tr. 1957 (Pietsch).

³⁴¹ Tr. 2123-25 (Pietsch).

capacities and conditions of the current TAPS, and thus does not have flexibility in throughput levels that is similar to the current TAPS.³⁴² It is not of similar quality and like utility to the existing TAPS.

c. Appraisal Theory

222. Under the cost approach, the goal is to estimate the cost of a new property with equal utility to the subject property, not a new plant with new utility.³⁴³ When as a factual matter, the physical plant, the capacity, the operations, and the capabilities of a hypothetical plant are different from the subject property, it does not give sufficient guidance on how to value the existing subject property.³⁴⁴ This is particularly true where the components of the subject property all contribute to the value of the property.

223. Other tribunals have found that a substitute property cannot be so dissimilar from the asset being valued that it does not represent a reasonable substitute. For example, in *American Crystal Sugar Company v. County of Polk*, the Minnesota Tax Regulation Division addressed whether it was proper appraisal practice under the cost approach to rely upon a cost study utilizing a hypothetical property with a substantially different design and capacity.³⁴⁵ The taxpayer argued that if the property were replaced, the building would be vastly different, but its expert appraiser could not identify any current

³⁴² Tr. 6453-54 (Hisey); Tr. 8108-16 (Modisette).

³⁴³ *The Appraisal of Real Estate* at 385; *Valuing Machinery and Equipment* at 44; Tr. 580 (Remsha); *American Crystal Sugar Co. v. County of Polk*, 2009 WL 2431376 at 21 (Minn. Tax Regular Div. 2009); *Fire Ins. Exch. v. Superior Court of Los Angeles*, 10 Cal. Rptr. 3d 617, 635 (Cal. App. 2d 2004); *Xerox Corp. v. Board of County Commissioners*, 87 P.3d 189, 192 (Colo. Ct. App. 2003) (holding that the cost approach is essentially an estimate of the cost of replacing the subject property with a new property that is equivalent in function and utility).

³⁴⁴ *American Crystal Sugar Co. v. County of Polk*, 2009 WL 2431376 at 21 (Minn. Tax Regular Div. 2009).

³⁴⁵ 2009 WL 2431376 at 18 (Minn. Tax Regular Div. 2009).

sugar beet plant that incorporated all of the modern design features that he proposed.³⁴⁶

The Minnesota tax division found that:

As a factual matter, under the Petitioner's cost approach, the physical plant, the capacity, the operations and the capabilities of the hypothetical plant are completely different [than what exists]. While the hypothetical plant may be an ideal standard, it does not give us sufficient guidance in how to value [the existing property] as it stands.³⁴⁷

The tax division further explained:

Under the cost approach we seek to value the building of a new plant with equal utility, not new utility. This would be like asking an appraiser to value a modest three bedroom house and getting back an appraisal on a ten bedroom mansion because that is what the owner would really want to build.³⁴⁸

Like the taxpayer in *American Crystal Sugar Company v. County of Polk*, the Owners' cost study is based on a hypothetical property that has very different capacity, operations, and capabilities than what currently exists on TAPS.

224. The Ohio Tax Board in *General Motors v. Cuyahoga County Board of Revision* reached a similar conclusion:

Appellant has failed to demonstrate that its theoretical Greenfield model is, in fact, an "equal" substitute for this facility. Its characteristics vary substantially. It is much smaller. This, in our view, limits its flexibility for adaptation of other uses. It is less likely to be adaptable to shifts in future production requirements because of this limited size. Less space is available for storage or other ancillary needs. Its utility is not "equivalent."³⁴⁹

³⁴⁶ 2009 WL 2431376 at 18 (Minn. Tax Regular Div. 2009).

³⁴⁷ 2009 WL 2431376 at 19 (Minn. Tax Regular Div. 2009).

³⁴⁸ 2009 WL 2431376 at 19 (Minn. Tax Regular Div. 2009).

³⁴⁹ *General Motors v. Cuyahoga County Board of Revision*, 1995 WL 38387 *13 (Ohio Bd. Tx. App. 1995).

225. The Owners have referenced *Chevron U.S.A., Inc. v. City of Perth Amboy*³⁵⁰ and assert that it is more on point than *American Crystal*. The Perth Amboy refinery was a fully integrated crude oil refinery until mid-1983 with a rated capacity of 168,000 bbl/d that processed a range of crude oils and produced a range of finished products.³⁵¹ After mid-1983, it became a 60,000 bbl/d refinery of heavy crude producing only one product: asphalt.³⁵² The New Jersey Tax Court held in 1988 that the property was correctly valued as an asphalt plant, as it could not return to full operations without a substantial investment – at a minimum, approximately \$80 to \$100 million.³⁵³

226. Unlike the Perth Amboy refinery, which had been an asphalt plant for five years at the time of the Tax Court's decision, TAPS' capacity and utility are unchanged – it is not currently a 30-inch, high pressure pipeline on mono-pile VSMs with freestanding thermosyphons.

227. A replacement property that does not incorporate all of the utility of the existing facility assumes that market participants do not place a value on all of the capabilities of the existing facility. But here, the evidence persuasively demonstrates that value has been placed on all of the capabilities of the existing facility including the ability of the 48-inch pipe to transport up to 2.1 million bbl/d of throughput. In effect, the Owners would redefine the subject property which is TAPS to instead constitute a pipeline that only transports the current throughput, with limited upward scalability. In this Court's view, such an approach is

³⁵⁰ 10 N.J. Tax 114 (N.J. Tax Ct. 1988), *superseded by Chevron U.S.A. v. City of Perth Amboy*, 11 N.J. Tax 480 (N.J. Super. App. Div 1989).

³⁵¹ *Perth Amboy*, 10 N.J. Tax at 118.

³⁵² *Perth Amboy*, 10 N.J. Tax at 118.

³⁵³ *Perth Amboy*, 10 N.J. Tax at 147.

inconsistent with appraisal theory and would result in a fundamentally improper valuation of TAPS. Instead, under appraisal theory, the statute's directive to accord "due regard" to the proven reserves and the current throughput should be addressed in the context of depreciation, and specifically economic obsolescence, of the subject pipeline.

228. Mr. Greeley, the State Assessor, testified that he had no specific knowledge of any cross-country pipeline in Alaska being valued by the Department based on a replacement cost new redesign that used a different diameter pipe than existed in the subject property.³⁵⁴

229. AS 43.56.060(e) directs that a pipeline be assessed "with due regard to the economic value of the property based on the estimated life of the proven reserves."³⁵⁵ Under standard appraisal theory, this statutory language does not warrant nor require that the existing property's upward scalability be ignored.³⁵⁶ Rather, the RCN should be based upon TAPS' actual design capacity. The fact that TAPS has upward scalability to carry throughputs of up to 2.1 million bbl/d enhances the pipeline's value. The Stantec design does not adequately incorporate this upward scalability.

d. The Stantec Design Is Unproven and Unknown

230. For many of the same reasons that this Court concluded that the Stantec design is not of similar quality and like utility to TAPS, the Court was not persuaded that the Stantec 30-inch pipeline design is physically possible and capable of being safely and effectively operated. The Stantec hypothetical 30-inch pipeline is, in part, based upon the

³⁵⁴ Tr. 6851-52 (Greeley). *See also* Tr. 12679 (Greeley); Tr. 6905 (Goodwin) (testifying that common carrier pipelines in Alaska are not valued based on redesign studies).

³⁵⁵ AS 43.56.060(e)(2) (emphasis added).

³⁵⁶ *See generally Valuing Machinery and Equipment* at 99-100.

application of design criteria that are unproven for cross-country pipelines, including its high pressure and its mono-pile VSMS without internal or integrated thermosyphons.³⁵⁷

231. A proposed replacement property should actually exist or be based on a proven design and technology for a particular environment, rather than based on an untested concept that does not have the same capability or utility as the existing subject property.³⁵⁸ This Court found Mr. Connolly's testimony regarding this topic to be particularly persuasive.³⁵⁹

232. When Stantec decided to use a 30-inch pipe for their cost estimate, they gave no consideration to a 1.1 million bbl/d throughput capacity.³⁶⁰ That higher capacity was added several months later.³⁶¹

233. Stantec uses six pump stations for its 2007 RCN, based on a design capacity of 900,000 bbl/d. It has five pump stations at the 750,000 bbl/d case for 2009.³⁶² To transport 1.1 million bbl/d, Stantec adds a seventh operating station.³⁶³ This variation in pump stations for different throughputs is an indication that the Stantec design has minimal flexibility.³⁶⁴ Mr. Hisey testified, "The 30-inch line that's running at or near its maximum design capacity, in my mind, wouldn't have much flexibility left. There wouldn't be much

³⁵⁷ Tr. 4646-48 (Steindorff).

³⁵⁸ Tr. 998-1003 (Connolly); *American Crystal Sugar Co. v. County of Polk*, 2009 WL 2431376 at 19 (Minn. Tax Regular Div. 2009).

³⁵⁹ Tr. 999-1003 (Connolly).

³⁶⁰ Tr. 3308-09 (Fiske).

³⁶¹ Tr. 8081-85, 8098-8100, 8111-12 (Modisette).

³⁶² Tr. 4472-73 (Steindorff). The 800,000 case for 2008 is also six pumps. Tr. 4472 (Steindorff); Tr. 5317 (Rein).

³⁶³ Tr. 4472 (Steindorff).

³⁶⁴ Tr. 4472-77 (Steindorff)

room for error. There wouldn't be much room for catch-up, either on day-to-day basis or a long-term basis.³⁶⁵

234. The Stantec design as proposed requires 80% drag reduction from DRA in order to be able to transport 1.1 million bbl/d.³⁶⁶ Mr. Pietsch's initial simulation in November 2009 based on a lower design capacity assumed 50%-65% drag reduction was reasonable. But in December 2010, Mr. Pietsch increased that to 80% drag reduction after acknowledging that there was not enough horsepower in the pumps to transport 1.1 million bbl/d if only 65% drag reduction was achieved.³⁶⁷

235. Mr. Pietsch utilized 80% drag reduction in his 1.1 million bbl/d simulation but acknowledged that he does not know of any other cross-country crude oil pipeline that operates with over 50% drag reduction effectiveness.³⁶⁸ Although Mr. Pietsch had authored papers on DRA reduction, he was not aware of any published literature using that high of a level of drag reduction.³⁶⁹ The maximum DRA reduction that he has ever seen for a crude oil pipeline was a simulation of the original TAPS Legacy pumps at 60%.³⁷⁰

236. Stantec relied on a promotional ConocoPhillips web page regarding a DRA product that indicated an 80% drag reduction could be attained. But the 80% drag reduction advertised on the web page is for an unspecified light crude and does not indicate pipe diameter or velocity (both of which could affect DRA performance).³⁷¹

³⁶⁵ Tr. 4960 (Hisey).

³⁶⁶ Tr. 2076-81 (Pietsch); Tr. 5148-49 (Riordan); Tr. 8078-80 (Modisette); Tr. 3865-66 (Ellwood), Tr. 4492-94 (Steindorff).

³⁶⁷ Tr. 2076-79 (Pietsch); Tr. 8078-80 (Modisette).

³⁶⁸ Tr. 2079 (Pietsch).

³⁶⁹ Tr. 2079 (Pietsch).

³⁷⁰ Tr. 2080 (Pietsch).

³⁷¹ Tr. 8103-07 (Modisette).

237. Dr. Modisette persuasively testified that there would be significant degradation of the DRA in the Stantec pipeline caused by the shear stress at the wall due to the higher flow velocity in the 30-inch pipeline.³⁷²

238. This Court was not persuaded that the requisite levels of drag reduction could be achieved on the Stantec pipeline.

239. Mr. Steindorff and Mr. Ellwood relied upon exhibit MUN7-1182, which lists seven pipelines with flow rates between 450,000 bbl/d and 1.0 million bbl/d, to support their opinion that the Stantec 30-inch pipeline design cannot effectively transport the actual throughputs during the lien years or the design criteria for TAPS.³⁷³ All of these pipelines have a larger diameter than the Stantec pipeline. Consistent with these findings, several witnesses testified that they do not know of a 30-inch pipeline anywhere in the world today that operates in excess of 500,000 bbl/d.³⁷⁴

240. Mr. Pietsch acknowledged that he has never simulated a 30-inch diameter pipeline that was actually constructed in which the design capacity was 1.1 million bbl/d, 900,000 bbl/d or 700,000 bbl/d.³⁷⁵ He has never before simulated a 30-inch crude oil pipeline that had one half the 1.1 million bbl/d flow rate of what he simulated in this case – i.e. 550,000.³⁷⁶ Further, Mr. Pietsch did not know of a 30-inch crude oil pipeline anywhere in

³⁷² Tr. 8113-14 (Modisette).

³⁷³ Tr. 6664-65 (Ellwood) (testifying that he relied upon exhibits MUN7-1196 to MUN7-1199, which include the underlying data for MUN7-1182); Tr. 4454-55 (Steindorff).

³⁷⁴ Tr. 3203 (Carson), Tr. 6895 (Greeley); Tr. 2029-30 (Pietsch); Tr. 6665 (Ellwood); Tr. 12500 (Remsha). See also Tr. 5297 (Rein) (testifying that he is not aware of a similar pipeline anywhere in North America or the world similar to the Stantec pipeline design).

³⁷⁵ Tr. 2029, 2072 (Pietsch).

³⁷⁶ Tr. 2029, 2031-32 (Pietsch).

the world that was operating at 1.1 million bbl/d.³⁷⁷ And he acknowledged that Stantec's ability to transport any throughput above 1.1 million bbl/d would be very limited.³⁷⁸

241. Mr. Pietsch also indicated that he had not done a simulation to show that the Stantec Valdez Terminal could operate at 1.1 million bbl/d.³⁷⁹

242. Many of the Owners' witnesses expressed absolute confidence in the design of the Stantec RCN. But this Court was left unpersuaded that the high level of confidence that was expressed was supported by the evidence. In this regard, the Court notes that the very high level of confidence with the 30-inch Stantec design was in direct contrast to the markedly pessimistic testimony by the Owners' witnesses about the ability of TAPS to operate below 300,000 bbl/d.

243. The Owners failed to persuade this Court that the Stantec design could operate as designed. Rather, this Court finds its design is unproven and unknown.³⁸⁰

e. The Stantec Design Does Not Capture All Costs

244. An RCN cost estimate should include all of the indirect and direct costs necessary to actually engineer and construct the replacement property. This Court was not persuaded that the Stantec RCN adequately captured all those costs. To cite one example, Stantec's study is not close to final bid, yet it has a contingency of less than 4%.

³⁷⁷ Tr. 2029-30 (Pietsch).

³⁷⁸ Tr. 2086 (Pietsch)

³⁷⁹ Tr. 2093 (Pietsch).

³⁸⁰ Tr. 11541 (Hoffbeck).

f. The Stantec Design Does Not Permit Adequate Quantification of Obsolescence

245. This Court finds that using an RCN with a smaller design capacity in order to take into account the obsolescence inherent in a subject property which is not using all of its capacity would result in over-counting of depreciation if that same obsolescence is also deducted from the reduced sized RCN in the depreciation stage of the cost analysis.³⁸¹

246. Additionally, adopting an RCN that is markedly dissimilar to the actual property being assessed and is instead designed based only on projected throughputs during each lien year would substantially increase the costs associated with determining the value of TAPS each year, since such an approach would likely require a new RCN each year with each increase or decrease in the throughput. In this regard, Mr. Hoffbeck's explanation of Mr. Treadwell's analysis is persuasive: the complications associated with a property redesign for a replacement cost study should be avoided. Instead, any obsolescence in the subject property may and should be cured with obsolescence adjustments to an RCN of similar quality and like utility to the subject property.³⁸²

247. The Stantec team has had extensive experience working in Alaska and other cold climates, as well as with Alyeska. Overall, this Court finds that the team effectively and capably undertook the task they were charged to undertake – to design a pipeline that appears to meet the minimum operating standards possible for crude oil transportation at the lowest cost, based on a design capacity determined from average daily throughput for each of the lien years. But, as explained in the above findings, that hypothetical pipeline is not an appropriate RCN to use to determine the assessed value of TAPS.

³⁸¹ Tr. 11543-54 (Hoffbeck).

³⁸² Tr. 1056 (Hoffbeck).

248. Alyeska employee Joe Riordan's loyalty and commitment to his employer was established beyond a reasonable doubt. And Mr. Riordan was very helpful to this Court in explaining some of the fundamentals of pipeline design and operations. And yet Mr. Riordan played a very active role in the development of the Stantec cost study. Indeed, he described himself as the "director" over the "cast" of experts for the Stantec RCN.³⁸³ This Court finds it more likely than not that Mr. Riordan's extensive involvement in many aspects of the Stantec RCN constrained the experts from forming independent opinions and resulted in an effort to minimize the overall cost of the Stantec RCN even if not technologically justifiable.

249. Stantec's RCN uses a 30-inch pipeline with physical properties, operations, design capacity, and capabilities that are completely different from the existing TAPS. It so deviates from the existing TAPS that it can not serve as a reasonable proxy in a replacement cost new study. In addition, its unproven design, including its high operating pressures, high velocities, high operating costs, and design issues related to the VSMS and freestanding thermosyphons make it more likely than not that such a pipeline would never be built – which is perhaps best demonstrated by the fact that there is no existing pipeline in the world that bears any reasonable approximation to the Stantec design.

250. For the above-stated reasons, the Court finds that Stantec's 30-inch pipeline is not an appropriate replacement pipeline to use as the basis for the application of the cost approach.

³⁸³ Tr. 1557, 1562 (Riordan).

3. The Pro Plus RCN

a. The Pro Plus Experts

251. The Pro Plus replacement cost estimate was prepared by pipeline and marine terminal engineers, contractors, and cost estimators with extensive experience, including engineer Gerald Steindorff, pipeline design expert John Ellwood, estimating and construction specialists Earl Tise and M. Kieth Phillips, and engineers Stan Lloyd and Jerry Baker, who specialize in marine facilities.³⁸⁴ Each witness's qualifications were discussed on record in detail.

252. The Pro Plus experts have a combined total of over 250 years of hands-on experience in engineering, project management, estimating, and construction of pipelines and terminal facilities.³⁸⁵ They have collectively estimated, managed and constructed several thousands of miles of cross-country pipeline in rugged terrain.³⁸⁶ With the exception of Mr. Baker, all of the Pro Plus experts testified before this Court. Mr. Phillips testified by perpetuated video deposition.

253. In addition, Dr. Jerry Modisette conducted hydraulic modeling to analyze the viability of the Pro Plus and Stantec pipeline designs. Dr. Mark Cronshaw addressed the RCN contingencies.

b. The Pro Plus Design

254. The Pro Plus design is a 48-inch diameter pipeline that is of similar quality and like utility to the existing TAPS.

³⁸⁴ Phillips Dep. 28.

³⁸⁵ Tr. 4459-60 (Steindorff); Tr. 4076 (Ellwood).

³⁸⁶ See Tr. 4080-8 (Tise); Tr. 3688-96, Tr. 3701 (Ellwood); Tr. 4460 (Steindorff); Phillips Dep. 71 (Aug. 22, 2011).

255. Pro Plus states that its design basis is 1.1 million bbl/d with upward scalability.³⁸⁷ This is essentially the same design basis as the existing TAPS pumps.³⁸⁸ But this Court finds that the Pro Plus 48-inch mainline pipe and VMT are comparable to the design capacity of the existing TAPS, which is 1.42 million bbl/d.³⁸⁹

256. Pro Plus's dual-pile VSM design is identical to the existing pilings and provides the necessary level of safety and protection against thawing of the permafrost as the existing facility.³⁹⁰ Pro Plus spaces the VSMs at approximately 60 foot intervals, per DB-180 requirements.³⁹¹

257. Pro Plus used floating roof tanks instead of the existing fixed roof tanks at the VMT. This Court finds that the Pro Plus VMT design is of similar quality and like utility to the existing TAPS.

258. Like TAPS, Pro Plus's pumps have three trains installed side by side, one pump per train.³⁹² The pumps are in parallel operation.³⁹³ Pro Plus's operating stations each have the same installed horsepower as on the TAPS SR pumps.³⁹⁴ However, Pro Plus has five operating stations, whereas the existing TAPS has four that have or will get the new SR pumps. Like the TAPS' SR pumps, the Pro Plus pumps have variable speed drive.³⁹⁵

³⁸⁷ MUN7-0008 at 10.

³⁸⁸ MUN7-9023 at 239; MUN7-1506 at 11, 13; MUN7-1553 at 6.

³⁸⁹ MUN7-0215.; Tr. 3716 (Ellwood); Tr. 2731 (Falcone); Tr. 7139-40 (Ray); MUN7-1137; MUN7-1553 at 6-7; MUN7-1182.

³⁹⁰ Tr. 3721 (Ellwood).

³⁹¹ Tr. 4500-02 (Steindorff); MUN7-9023 at 72; MUN7-0008 at 15. *See also* Tr. 3128-29 (Meyer).

³⁹² Tr. 4474 (Steindorff); Tr. 8085 (Modisette).

³⁹³ Tr. 4474 (Steindorff).

³⁹⁴ Tr. 4472 (Steindorff).

³⁹⁵ Tr. 4472 (Steindorff).

Like TAPS, at each station, Pro Plus has three 6500-horsepower units. At lower throughputs, one set of pumps is unnecessary and serves as a spare.³⁹⁶

259. Pro Plus uses a granular work pad along most of the length of the pipeline.³⁹⁷ A granular work pad provides the ability to work in multiple seasons, reduces the risk of non-completion, and provides summer access for continued maintenance of TAPS and contingency purposes.³⁹⁸ Mr. Baldrige, an Alyeska employee, testified to the utility and benefit of TAPS having the current work pad.³⁹⁹ The Court finds that Pro Plus's use of granular work pads is reasonable, and that the continued benefit of the existing work pads on TAPS would not be captured in an RCN of TAPS that used predominantly ice roads.

260. Pro Plus used the existing route of TAPS with some minor realignments – about three tenths of a mile – to facilitate directional drilling at some of the river crossings and in the Fairbanks area to avoid the buildup area that did not exist when the original route was selected.⁴⁰⁰ The Court finds that Pro Plus's route has the same utility as the current route and the slight deviations are reasonable.

261. The Owners established that Pro Plus's estimate did not include all of the essential components for a pipeline from PS 1 to Valdez – for example, the Pro Plus estimate did not include safety flares at PS 1.⁴⁰¹ But the goal of an RCN estimate is for

³⁹⁶ Tr. 4472-73 (Steindorff); Tr. 8085 (Modisette).

³⁹⁷ Tr. 3862-63 (Ellwood).

³⁹⁸ Tr. 1243-45 (Baldrige); 3862-63 (Ellwood).

³⁹⁹ Tr. 1243-45 (Baldrige); 3862-63 (Ellwood).

⁴⁰⁰ Tr. 3719-20, 3861 (Ellwood); Tr. 4471, 4512 (Steindorff).

⁴⁰¹ Tr. 1595 (Riordan).

comparison purposes to an existing property. It is not intended to be a fully detailed, comprehensive cost estimate.

c. The Pro Plus Cost Estimate

i. Direct Costs

262. In preparing pipeline construction estimates, costs are identified as direct and indirect. The Pro Plus estimate categorizes the following direct costs: Survey, Pipeline Material, Pipeline Installation, Pump Station Facilities, Pump Station Installation, Meter Station Facilities, Meter Station Installation, Valdez Marine Terminal, and Pipeline Systems.⁴⁰² Pro Plus estimated the direct costs at \$11.4 billion for 2007, \$12.5 billion for 2008, and \$12.4 billion for 2009.⁴⁰³

a) Pipeline Materials

263. The Pro Plus RCN utilizes many of the original quantities for TAPS to determine the necessary pipeline material. Pipe diameter, wall thickness, grade, and lengths used are those described in the "Alyeska Facts" booklet.⁴⁰⁴ The line pipe estimate includes the 48-inch pipe used to transport crude oil, the 8-inch and 10-inch pipe used to transport fuel gas, and the 18-inch pipe used for the VSM:

[W]e have carefully reviewed these quantities, sizes, etc. and have concluded they are still the most appropriate for the 1.1 million barrel per day design flow used as the basis for the RCN estimates. Maintaining the pipe diameter, wall thickness, etc. the same as the original design should not be confused with the use of modern versus 1970's materials. The estimated costs presented herein are based on up to date material specifications, steel pipe manufacturing process, coatings, welding processes, etc. Utilizing the same diameter and wall thickness for the pipe provides the same functionality as the

⁴⁰² MUN7-0008 at 1628; Tr. 3726-27 (Ellwood); Tr. 4634-35 (Steindorff).

⁴⁰³ MUN7-0008 at 1628.

⁴⁰⁴ MUN7-1103.

existing facilities while minimizing costs through use of modern materials and construction methods.⁴⁰⁵

The Alyeska Facts book is updated regularly and contains one of the best public sources of the actual materials in place on TAPS.

264. The Pro Plus team then developed C-plans, which Mr. Ellwood and Mr. Tise explained are used to generate “a take-off of things that needed to be included in the [Pro Plus] estimate,” such as the contours and grades of the terrain, the number of flume pipes, the river and road crossings, and the placement of valves.⁴⁰⁶ As an example, referencing Aerial Maps 27 and 28 of the C-Plans, Mr. Tise testified:

I used that to indicate that we left the pipeline above ground at mile 12 1/2; and if you will look at Aerial Map 28, you will see that below mile 53 – in fact, I think we carried it as 53 1/2. But you will notice that the pipelines come from belowground to above ground. So it’s been 40 miles of pipe belowground.⁴⁰⁷

265. After some study, Pro Plus adopted the above and below ground configurations on the existing TAPS.⁴⁰⁸ Mr. Tise calculated the number of miles of above and below ground pipe for each section, indicating the mile where the pipe transitions from above to below ground,⁴⁰⁹ then used the Alyeska Atlas to verify his takeoffs.⁴¹⁰

266. For the VSMs, Mr. Ellwood and Mr. Steindorff testified that they used information provided by the Joint Pipeline Office (“JPO”) to determine the amount of steel

⁴⁰⁵ MUN7-0008 at 14.

⁴⁰⁶ Tr. 3743-44; 3791 (Ellwood); Tr. 4117-38 (Tise) MUN7-1100.

⁴⁰⁷ Tr. 4133 (Tise); MUN7-1100 at 155.

⁴⁰⁸ MUN7-0008 at 9; Tr. 4133-34 (Tise)

⁴⁰⁹ Tr. 4145 (Tise); Tr. 4449 (Steindorff); MUN7-1113 at 6-9.

⁴¹⁰ Tr. 4133, 4145-46; MUN7-1101.

needed for the VSMs and then calculated the weight of that steel and obtained budgetary quotes to fabricate the VSMs.⁴¹¹

267. Pro Plus utilized the same grade of line pipe as the existing TAPS – X-65 and X-70, with wall thicknesses of .462 inches and .562 inches.⁴¹²

268. The Owners critiqued Pro Plus's choice of X-65 and X-70 grade steel instead of the X-80 grade that was used in the Stantec cost estimate.⁴¹³ X-80 grade has a greater yield strength and would have been necessary for the higher pressure on Stantec's 30-inch pipe.⁴¹⁴ But Mr. Steindorff persuasively testified that X-65 and X-70 grade steel are the most appropriate and most economical choice for the 48-inch pipeline.⁴¹⁵ A thinner, higher grade pipe could cause problems with the 48" pipe such as ovality, buckling and bending.⁴¹⁶ The evidence also demonstrates that X-65 and X-70 are commonly used steel strengths in modern pipelines.⁴¹⁷

269. Mr. Steindorff provided a detailed explanation on how Pro Plus derived the materials costs of its 48-inch mainline pipe.⁴¹⁸ Pro Plus estimates that a 48-inch mainline pipe would cost \$1,791 per ton for 2007, \$2,548 for 2008, and \$2,033 per ton for 2009.⁴¹⁹

⁴¹¹ Tr. 3798, 3869-70 (Ellwood); Tr. 4449 (Steindorff); MUN7-1109. Pro Plus had this information regarding the steel members before the 2006 ad valorem tax matter and it was incorporated into the study presented to this Court. Tr. 3870 (Ellwood).

⁴¹² Tr. 3716-17 (Ellwood); Tr. 4509-12 (Steindorff).

⁴¹³ Tr. 5090-92 (Riordan).

⁴¹⁴ Tr. 1589 (Riordan); Tr. 2953 (Ziehr).

⁴¹⁵ Tr. 4511-12, 6618-19 (Steindorff). See also Tr. 3716:16-17, 3892-94 (Ellwood).

⁴¹⁶ Tr. 3716-17 (Ellwood); Tr. 4509-12 (Steindorff).

⁴¹⁷ See e.g., Tr. 5449 (Jens); Tr. 6499-6500 (Tise); Tr. 6534-35 (Tise).

⁴¹⁸ Tr. 6599-6602 (Steindorff).

⁴¹⁹ Tr. 6599 (Steindorff); MUN7-0008 at 44, 575, 1107.

Pro Plus solicited quotes directly from several North American mills (rather than obtaining them as Michels Canada did from pipeline distributors for Stantec).⁴²⁰

270. Logistically, Pro Plus railed the pipe to Seattle for transport by barge and rail to Valdez and Fairbanks to double-jointing yards.⁴²¹ From the double-jointing yards, the pipe would be trucked to stockpiles along the right-of-way for use by the pipeline contractor.⁴²²

271. At trial, Pro Plus indicated that its materials estimates should not have included a line item for insulation of the work pad, which they had estimated at approximately \$34 million per year.⁴²³

b) Pipeline Installation

272. Pro Plus relied upon numerous documents to determine the costs for the pipeline installation, together with their expertise and experience. These documents included the Alyeska Contingency Plan (“C-Plan”) drawings, Alyeska Facts booklet, TAPS ROW Map Atlas, Google Earth, and the Alyeska alignment sheets (G-100 Drawings).⁴²⁴

273. The Owners’ experts particularly criticized Pro Plus’s productivity rates, labor rates, and equipment rates.

274. Productivity rates can be impacted by several factors, including weather, terrain, time of year, start and completion dates, environmental restrictions, contractor availability, and the availability of labor and equipment.⁴²⁵

⁴²⁰ Tr. 6599-6600 (Steindorff) (relying on MUN7-1105).

⁴²¹ Tr. 6600 (Steindorff); MUN7-1106 at 1-4.

⁴²² Tr. 6600 (Steindorff); MUN7-1106.

⁴²³ See, e.g. MUN7-0008 at 1107.

⁴²⁴ Tr. 3792-93 (Ellwood); Tr. 3793-94 (Ellwood); Tr. 4117-18 (Tise); MUN7-1100; MUN7-1101; MUN7-1103.

⁴²⁵ Phillips Dep. 37, 39, 40, 43, 44, 46, 47, 51, 52.

275. Mr. Tise discussed in detail how March Charts and crew-up sheets were created and utilized by Pro Plus to determine pipeline installation costs.⁴²⁶ He explained how the C-Plans assisted in the determination of the progress rate in each section. For example, utilizing page 125 of the C-Plans,⁴²⁷ Mr. Tise stated:

[i]f you can look at the contours, you can see how close they are together, being in that section, it's going uphill from just below Pump Station 12. And from experience, I know that those grades are 30 percent to 70 percent; and I know that they were also – more than half of them were rock. So that helped in crewing-up, seeing how much progress we could get. And then if you look above Pump Station 12, you notice that it's flat. So we have designations from flat to mountain, of about six of them, that just increase in the degree of difficulty ... This section was about 147 miles. And we came up with how much of it was flat, how much of it was rolling, and so forth to come up with progress rates.⁴²⁸

276. The Owners' experts argue that Pro Plus's productivity rates for welding are too low, and therefore affect the overall construction schedule. However, based on the evidence presented, this Court finds that the welding rates do not control the pace of the Pro Plus RCN construction project.⁴²⁹ Mr. Ellwood persuasively testified that "[i]n a pipeline job, the whole operation must move only as fast as the slowest crew. And in our view, what we call putting the pipe in the ditch or, in this case on the VSMS, in places will control the pace for the most of this project."⁴³⁰

⁴²⁶ Tr. 4147-50, 6529-30 (Tise); MUN7-1115; MUN7-1116; Phillips Dep. 23-24; Tr. 3747-48 (Ellwood); Tr. 4147-48 (Tise); Tr. 4449 (Steindorff); MUN7-1115; Phillips Dep. 23-24, 25-26, Tr. 3749-50 (Ellwood), Tr. 4147-48 (Tise); MUN7-1115.

⁴²⁷ MUN7-1100.

⁴²⁸ Tr. 4120-21 (Tise).

⁴²⁹ Phillips Dep. 37-39; Tr. 3740 (Ellwood).

⁴³⁰ Tr. 3740 (Ellwood).

277. In determining the productivity rate, Pro Plus also considered the shortage of pipeliners during the lien years due to extensive pipeline construction activity in the United States during that time.⁴³¹ Given that shortage and the remote and isolated location of Alaska, Mr. Tise testified that in the lien years,

[y]ou're not going to get the A team and you're not going to get the B team; they're all already working ... the journeymen hours are for those three years [It's] more than any three-year – back ... to 1965. Even including the years that [TAPS] was being built, you've already exceeded the man-hours for those years by about 300 percent⁴³²

278. In addition, Pro Plus took into account that 420 miles of the pipeline will be above-ground and that those portions will take longer to install because the pipe has to fit into all the VSM supports through challenging terrain.

279. Regardless of what work sets the pace for the pipeline construction, this Court finds that Pro Plus's overall welding rates are reasonable.⁴³³ Pro Plus estimates approximately 50 joints per day.⁴³⁴ As Mr. Phillips explained, the welders will have to achieve 75 joints on some days in order to achieve an average of 50 joints per day because there will be days in which none or very little welding is achieved due to weather, delays in the other crews, or equipment failures.⁴³⁵

280. Pro Plus's estimate includes the cost of automatic welding for sections 1, 3, 4, and 5 and manual welding for sections 2 and 6.⁴³⁶ Pro Plus assumed that because manual

⁴³¹ Phillips Dep. 39-42.

⁴³² Tr. 4168 (Tise). See also Phillips Dep. 39-42 (relying on MUN7-1201 (Hours Worked in the Pipeline Industry, Historical (Cash) Based (1965-2011))).

⁴³³ See Tr. 4152-56 (Tise); Phillips Dep. 63-64.

⁴³⁴ Phillips Dep. 52-53.

⁴³⁵ Phillip Dep. 52-54.

⁴³⁶ Phillips Dep. 56-57, 62; Tr. 4462 (Steindorff).

welding would be needed in difficult constructions areas in sections 2 and 6 -- specifically in Atigun Pass and Thompson Pass⁴³⁷ -- manual welding should be used in each of those entire sections.

281. This Court found the Owners' critique on this issue persuasive. That is, this Court was unpersuaded that because of the challenges presented by Atigun Pass and Thompson Pass, the entire two spreads that encompassed those passes should be manually welded.⁴³⁸ But overall, this Court finds that Pro Plus's productivity rates are reasonable.

282. The majority of the experts acknowledged that the owners, contractors, and unions would negotiate and enter into a project labor agreement for the construction of a pipeline system and marine terminal of the length, size, and complexity of TAPS.⁴³⁹ Mr. Ellwood persuasively testified that before committing the billions of dollars needed to build a pipeline, a project labor agreement would be needed to provide some certainty to the labor situation.⁴⁴⁰

283. An owner that was contemplating the building of a new TAPS would want to assure predictability, labor certainty, and a "no-strike" condition to assure the completion of the project.⁴⁴¹ Contractors would need to know the rates they would have to pay their labor

⁴³⁷ Tr. 4462-63 (Steindorff).

⁴³⁸ Phillips Dep. 59-60.

⁴³⁹ Tr. 3751 (Ellwood); Phillips Dep. 73-74; Tr. 2994 (Ziehr); Tr. 5427 (Jens); Tr. 6159 (Bock); Tr. 5656 (Sherman); Tr. 5801 (Karlík); Tr. 4938 (Dotson) (indirectly); TO-07-0021 at 0700; Tr. 4427 (Steindorff).

⁴⁴⁰ Tr. 3751 (Ellwood).

⁴⁴¹ Phillips Dep. 86; Tr. 3751 (Ellwood).

force prior to bidding the project. The unions would want to ensure their members obtain adequate wages, benefits, and living and working conditions.⁴⁴²

284. This Court finds that the evidence persuasively showed that a labor agreement for constructing TAPS would start with the Pipe Line Contractors Association (“PLCA”).⁴⁴³ The PLCA negotiates wages, benefits, working conditions, and other terms with the four main pipeline trades (Journeyman, Laborers, Teamsters, and Operators) and publishes the labor rates for each state annually.⁴⁴⁴ However, no labor rate has been published by the PLCA for Alaska during the years at issue in this litigation.⁴⁴⁵

285. Pro Plus’s estimate tries to determine what the outcome of the PLCA negotiation would have been.⁴⁴⁶ Pro Plus did not call any local Alaska labor unions to determine their current rates, even for those trades that are not covered by the PLCA.⁴⁴⁷ Labor rates from local unions typically are lower than PLCA rates.⁴⁴⁸

286. Pro Plus’s estimate assumes that all workers doing similar work will be paid the same regardless of the location of their assignments.⁴⁴⁹ For example, Pro Plus assumes that a crane operator working on the pipeline and a crane operator working at the VMT would both receive the same wages because the project labor agreement would be negotiated to cover all workers. At least with respect to work at the VMT, this Court was not

⁴⁴² Tr. 3751-53 (Ellwood).

⁴⁴³ Phillips Dep. 73-74; Tr. 3751-52 (Ellwood); Tr. 2994 (Ziehr); Tr. 4938 (Dotson); TO-07-0021 at 0700; Tr. 4494-95 (Steindorff); Tr. 5656 (Sherman).

⁴⁴⁴ Phillips Dep. 12-13, 73-74; Tr. 3752 (Ellwood), 4143 (Tise); MUN7-1117 at 8-9.

⁴⁴⁵ Tr. 3754 (Ellwood).

⁴⁴⁶ Tr. 4494-95 (Steindorff); Tr. 3752; Tr. 3754, 4033-34 (Ellwood).

⁴⁴⁷ Tr. 4033-34 (Ellwood).

⁴⁴⁸ Tr. 4497 (Steindorff).

⁴⁴⁹ Phillips Dep. 87-89; Tr. 4426-27 (Lloyd).

persuaded that this assumption was reasonable. Rather, more likely than not a worker who was expected to stay in camps and operate cranes at remote locations along the pipeline route would expect and obtain a higher wage than a crane operator who would be residing in Valdez for the duration of his employment on the project.

287. The Pro Plus study utilized the published PLCA rates for California for each year and added approximately 15% as a likely incentive to get workers to Alaska for the job.⁴⁵⁰ Pro Plus also added double time for Sundays and included four hours wages per day when the worker was off-duty (paid only when the worker returned to the job).⁴⁵¹ Pro Plus experts testified that the remote location, the camp and weather conditions, and the worker's isolation from their families warranted these adjustments to the labor rates that would be negotiated for the construction of TAPS.⁴⁵²

288. Pro Plus did not include any per diem or welder rig rates,⁴⁵³ had they done so, their estimated rates estimated would have been higher.⁴⁵⁴

289. Relying on a comparison of a Lower 48 journeyman rate with the Alaska journeyman rate during construction of TAPS in the 1970's, Mr. Tise noted that the increase in wages for Lower 48 journeymen working in Alaska for construction of TAPS was between 19 – 28%.⁴⁵⁵ That range is higher than the rate utilized by Pro Plus, which added 15% to the California rates.⁴⁵⁶

⁴⁵⁰ Phillip Dep. 31-32, 73, 78-79; Tr. 3762-63 (Ellwood); Tr. 5669-70 (Sherman).

⁴⁵¹ Phillips Dep. 84-85; Tr. 3762-63 (Ellwood).

⁴⁵² Phillip Dep. 31-32, 73, 78-79, 84-85.

⁴⁵³ Cf. TO-07-0044 at 0068.

⁴⁵⁴ Phillips Dep. 81-82.

⁴⁵⁵ Tr. 4141-42 (Tise); MUN7-1117 at 3.

⁴⁵⁶ Phillips Dep. 77-78; Tr. 3766 (Ellwood); Tr. 4140 (Tise); MUN7-117 at 8-17; MUN7-1205.

290. The Owners hired Hawk Consultants LLC ("Hawk") to critique the RCN estimate prepared by Pro Plus for the 2007 to 2009 lien years. The Hawk experts did not present a comprehensive critique of the Pro Plus estimate, but only looked at certain limited topics. And each Hawk expert only reviewed his assigned portion of the Pro Plus estimate and did not read any depositions of Pro Plus experts or their transcripts either before this Court in the 2006 litigation or before SARB in 2009, 2010, or 2011.⁴⁵⁷

291. Jeff Sherman was one member of the Hawk team who looked at labor rates. Of note, Mr. Sherman's overall production cost per mile for the welding crew (which would have necessarily included all of those factors) was very close to that of Pro Plus's estimate.⁴⁵⁸ Mr. Sherman calculated that the Pro Plus cost per mile for their welding crew was \$98,712.⁴⁵⁹ Hawk's cost per mile was \$98,907.⁴⁶⁰

292. Overall, this Court finds that Pro Plus's rates for the four PLCA trades are reasonable, including its use of the California base rate with 15% markup, except that this Court was persuaded by the Owners' experts that the use of Sunday double time and compensation at the rate of four hours per day on off dates would, more likely than not, not be included within a project labor agreement.

293. Pro Plus determined the wage rates for the remaining trades and the salaried staff by adjusting from the PLCA rates. But this Court was persuaded by Mr. Sherman's testimony that the labor rates used for the non-PLCA trades and the salaried staff in the Pro Plus estimate are generally too high. While some upward adjustment to those wages from

⁴⁵⁷ Tr. 5637 (Sherman).

⁴⁵⁸ Tr. 5677 (Sherman).

⁴⁵⁹ Tr. 5676-77 (Sherman).

⁴⁶⁰ Tr. 5676-77 (Sherman). *See also* TO-07-0044.0075; Tr. 5715-16 (Sherman).

Alaska labor rates is warranted due to the fact that a project of this magnitude will necessarily increase the cost of labor and due to the remoteness of the work, overall this Court finds that Pro Plus's adjustment overcompensated for these factors for the non-PLCA trades and the salaried staff.

294. To determine equipment rates, Pro Plus used bids from previous big-inch, cross-country pipelines information from Caterpillar Company, and prices for 2007, 2008, and 2009 from PipeLine Machinery, a pipeline rental/sales company in Houston.⁴⁶¹

295. Hawk consultant witnesses criticized the Pro Plus cost estimate for having equipment on site for the full duration of the construction. Mr. Ellwood testified that it is necessary to have equipment for the duration of the project because in many of the construction sites equipment will not be available, particularly on short notice.⁴⁶² Pro Plus testified that there is a limited amount of construction equipment available for rent in Alaska. For example, Mr. Tise testified that in 2008, there was no 594 sideboom in Alaska to rent.⁴⁶³ Contractors also do not want to rely upon small-scale dealers to service their needs so they will not rent locally.⁴⁶⁴ Equipment rented out of state entails additional cost to winterize it and transfer it to Alaska.⁴⁶⁵ But this Court was persuaded by the Hawk experts that there appears to be at least some instances where the Pro Plus estimate had included too much or too many days of equipment in its estimate.

⁴⁶¹ Phillips Dep. 31, 93-98; Tr. 4162-64 (Tise); MUN7-1118.

⁴⁶² Tr. 3738 (Ellwood). See also Phillips Dep. 69-71.

⁴⁶³ Tr. 6529 (Tise).

⁴⁶⁴ Tr. 4024 (Ellwood).

⁴⁶⁵ Tr. 3775 (Ellwood).

296. Pro Plus applied a mark-up of 15% of the subcontract amount for a handling fee.⁴⁶⁶ Hawk Consultants assert that this percentage is too high.⁴⁶⁷ This Court was persuaded that a 15% handling fee for handling the subcontracts in this case is too high, and that 10% would be a more appropriate amount -- the same amount that Pro Plus applied to owner's costs, which has somewhat comparable oversight responsibilities.

297. Mr. Tise and Mr. Steindorff provided detailed explanations on how Pro Plus derived their pipeline camp cost estimates.⁴⁶⁸ They also explained their reliance on the budgetary quote from International Camp Sales and Services, Inc., and the additional costs that were not included in that bid such as transportation to the site, erection costs, commissioning costs, and single man sleepers.⁴⁶⁹ While the original TAPS construction had 29 camps, Pro Plus reduced the number of camps necessary to 6 larger camps and a total of 13 camp locations. The total camp capacity is 10,750 beds.⁴⁷⁰ Pro Plus has anticipated in its RCN that "the peak manpower will be approximately one-third of the peak manpower during the initial construction."⁴⁷¹

298. While the Owners' experts from Hawk critiqued the Pro Plus pipeline camp estimates, the Stantec estimates were higher. For example, in 2009, Stantec estimated

⁴⁶⁶ MUN7-0008 at 95, 96.

⁴⁶⁷ Tr. 5969 (Bock).

⁴⁶⁸ Tr. 4158-61 (Tise); Tr. 6606-08 (Steindorff); MUN7-0008 at 737.

⁴⁶⁹ Tr. 4937-4938 (Dotson). See also Tr. 4937-38 (Dotson); Tr. 4158-61 (Tise); Tr. 6606-08 (Steindorff) (relying on MUN7-1112 at 8-10).

⁴⁷⁰ MUN7-0008 at 17. See also MUN7-1103 at 14.

⁴⁷¹ MUN7-0008 at 17

camp costs at \$1.6 million,⁴⁷² while Pro Plus estimated camp costs for that year at approximately \$1.4 million.⁴⁷³

299. For these reasons, the Court finds that the Pro Plus experts adequately demonstrated that their cost estimate for the pipeline camps is reasonable.

300. Pro Plus included a line item for miscellaneous expenses that will be incurred by the contractor totaling 40% of direct labor for each lien year.⁴⁷⁴ Within the miscellaneous expenses, Pro Plus includes 20% of direct labor for small tools and consumables.⁴⁷⁵ Mr. Phillips and Mr. Tise testified that 20% of direct labor for small tools and consumables is typical for contractors.⁴⁷⁶ But based on the totality of the evidence presented at trial on this issue, this Court finds these amounts should be no more than 10% of direct labor. Pro Plus has also accounted for the cost of safety orientation, environmental orientation, background checks, physicals, and administrative work related to turnovers within the 40%, and Pro Plus has assumed that these costs will be 15% of direct labor costs.⁴⁷⁷ With respect to these items, this Court also found Hawk's analysis persuasive, and concludes that these expenses should total no more than 10% of labor costs. Pro Plus also calculated that the contractors will incur 5% of direct labor costs for unscheduled overtime. But this Court finds that including this as a separate entry in addition to the 30% adjustment that Pro Plus identifies

⁴⁷² TO-07-0025 at 0651.

⁴⁷³ MUN7-0008 at 42 (\$712,195,300 for camp materials) and MUN7-0008 at 204, 253, 303, 352, 401, 450 (approximately \$113,000,000 for pipeline camp installation cost for spreads 1-5 and \$144,000,000 for spread 6).

⁴⁷⁴ Phillips Dep. 93-99. See, e.g., MUN7-0008 at 58, 95, 114, 132, 150, 169, 186, 203.

⁴⁷⁵ Phillips Dep. 94-97, 98.

⁴⁷⁶ Phillips Dep. 94-95.

⁴⁷⁷ Phillips Dep. 96-98

for “weather equipment labor” entails a significant risk of double counting.⁴⁷⁸ With these adjustments, this Court finds that the total miscellaneous expenses should be no more than 20% of direct labor.

301. Pro Plus’s estimate also includes a 30% contractor’s risk for “weather equipment labor.”⁴⁷⁹ Typically this cost is embedded in the contractors’ bids, and the owner does not know the exact percentage utilized in the contractor’s bid.⁴⁸⁰ In a project of this size and scope, the contractor will assume a certain amount of risk associated with weather, equipment, and labor in its bid.⁴⁸¹ But this Court found persuasive the Owners’ assertion that Pro Plus’s estimate of this amount is too high. Given the other concerns separately identified with respect to the over-estimation of equipment usage and staff and non-trade wage rates, no more than 25% should be allocated for contractor’s risk in the Pro Plus bid, an amount comparable to the overall contingency that has also been included in the Pro Plus cost estimate.

c) Pump Station Facilities

302. Pro Plus’s estimated costs of the pump and meter stations are based on the design specified in the “Alyeska Facts” booklet, the “Pipeline Oil Discharge Prevention and Contingency Plan” (“C-Plan”), and the Design Specification for the SR project currently being implemented, along with modern design and construction techniques common to the industry.⁴⁸² Budgetary quotes were obtained for major equipment and material.⁴⁸³ For other

⁴⁷⁸ Phillips Dep. 96-97.

⁴⁷⁹ Phillips Dep. 100-101.

⁴⁸⁰ Phillips Dep. 19-22.

⁴⁸¹ Phillips Dep. 100-103.

⁴⁸² Tr. 4460-61 (Steindorff).

items, Pro Plus relied on estimates based on previous project experience and a historical database.⁴⁸⁴

303. The 2007 “Alyeska Facts” booklet states that there are six pump stations that were then currently operating: Pump Stations (“PS”) 1, 3, 4, 5, 7 and 9. Of these, PS 5 is a relief station that does not contain mainline pumps.⁴⁸⁵ PS 7 currently has the original Legacy pumps. The 2007 Facts book does not include PS 7 as one of the pump stations that is scheduled for the strategic reconfiguration (SR) pump upgrades.⁴⁸⁶ In an order dated April 6, 2005, the RCA concluded that “pump stations 7 and 12 are no longer necessary for future TAPS operation.”⁴⁸⁷ However, PS 7 is the location of Alyeska’s current recirculation project to increase the heat of the oil without the cost of acquiring a heater.⁴⁸⁸

304. The Pro Plus cost estimate generally follows SR and DB-180 and the SNC Lavalin Study with respect to the pumps, tanks, fuel gas line, power generation, and maintenance systems.⁴⁸⁹ But the Pro Plus cost estimate differs by designing PS 7 to have the newer SR pumps and by adding pig launchers and receivers to further simplify pipeline operations.⁴⁹⁰ The existing PS 7 does not contain any SR pumps as of the respective lien dates, nor is there any electric utility tie-in to PS 7.⁴⁹¹ Upon consideration of all the evidence, this Court finds Pro Plus’s inclusion of PS 7 with SR pumps in its RCN was not

⁴⁸³ Tr. 4451 (Steindorff); MUN7-1100; MUN7-1103; MUN7-1127-1131; MUN7-0008 at 23-24.

⁴⁸⁴ MUN7-1127 to MUN7-1131.

⁴⁸⁵ MUN7-1103 at 48. See also Tr. 3724 (Ellwood).

⁴⁸⁶ MUN7-1103 at 56.

⁴⁸⁷ MUN7-1506 at 11.

⁴⁸⁸ Tr. 9011-13 (Modisette).

⁴⁸⁹ Tr. 4460-61 (Steindorff).

⁴⁹⁰ Tr. 4513 (Steindorff).

⁴⁹¹ Tr. 1200 (Baldrige).

unreasonable, and that the difference between the Pro Plus RCN and the existing TAPS in this regard is best addressed in determining depreciation.

305. Pro Plus's design did not include a PS 12, although that station may be necessary to the cold restart operations of TAPS. Given that TAPS has not ever used PS 12 for cold restart, the omission of this pump station from the Pro Plus RCN was reasonable. In any event, if PS 12 was required it would increase the cost of the RCN.⁴⁹²

306. Pro Plus created schematics, process flow diagrams, and conceptual layout plans for the pump station facilities.⁴⁹³ The Owners' experts criticized Pro Plus for not including certain items in their process flow diagram.⁴⁹⁴ But the process flow diagram was created to show the main flow of the crude oil; it was not intended to show auxiliary systems and minor piping.⁴⁹⁵

307. Owners' expert Mr. Riordan persuasively testified that the majority of the pipeline in the Pro Plus pump station was 48 inches which was unnecessary and costly.⁴⁹⁶ Instead, smaller diameter piping can be used within the pump stations.

308. The Pro Plus installation costs of the pump stations are based on modular construction and developed utilizing the same "crew up" methodology that Pro Plus used for the pipeline installation. Mr. Ellwood and Mr. Tise persuasively testified that the "crew-up"

⁴⁹² See Owners' Proposed Findings of Fact and Conclusions of Law ¶ 58. See also Tr. 1199-1200 (Baldrige).

⁴⁹³ Tr. 3744-45; 3746 (Ellwood); Tr. 4451; MUN7-1132.

⁴⁹⁴ Tr. 1640-43 (Riordan); Tr. 4513-16 (Steindorff).

⁴⁹⁵ Tr. 4514 (Steindorff) (discussing MUN7-1132 at 11).

⁴⁹⁶ Tr. 5097-99 (Riordan). See also Tr. 4516-17 (Steindorff). The piping into the pumps is 24 inches. Tr. 4516-17 (Steindorff); Tr. 3732 (Ellwood).

method is used by contractors for facility work because it provides detailed information, such as the equipment, manpower, and the duration required for the work.⁴⁹⁷

309. A comparison of Pro Plus's direct cost estimate for pump stations with Stantec's is helpful.⁴⁹⁸ In 2007, Stantec's estimate for the direct cost of pump stations is \$812,871,643 for its 900,000 bbl/d throughput design. The additional cost for the 1.1 bbl/d throughput totals \$415,044,990, for a total cost of approximately \$1.2 billion.⁴⁹⁹ Pro Plus's estimate of the total direct cost for all the pump station facilities, including installation and materials, is comparable at \$1.0245540 billion for the 2007 lien year.⁵⁰⁰

310. Apart from the concerns identified as stated above (including those identified with respect to pipeline installation that would be applicable here as well), based on the evidence presented at the de novo trial, this Court is persuaded that overall Pro Plus's cost estimate for pump stations resulted in a proper valuation.

d) Valdez Marine Terminal

311. Lloyd Engineering performed the estimating work for the VMT portion of the Pro Plus estimate. Mr. Lloyd estimated the terminal facilities taking into account the relationship between the terminal, the pipeline minimum and maximum capacities, pipeline shut down allowance, the weather in Valdez, and berth availability for the tanker fleet.⁵⁰¹

⁴⁹⁷ Tr. 3732-42, 6652-54 (Ellwood); Tr. 4117-18 (Tise); Tr. 4495-96 (Steindorff).

⁴⁹⁸ Compare TO-07-0021 at 546, 684 with MUN7-0008 at 41-42.

⁴⁹⁹ TO-07-0021 at 546, 684.

⁵⁰⁰ MUN7-0008 at 41-42 (\$507,139,600 plus \$495,315,800).

⁵⁰¹ MUN7-0008 at 25-26.

The evidence demonstrated that the Pro Plus VMT design matches the flexibility of the 48-inch pipeline design and maintains the current flexibility of TAPS.⁵⁰²

312. Mr. Lloyd estimated a lay berth and two loading berths in the Pro Plus VMT.⁵⁰³

The Owners critique the inclusion of the third lay berth. However, the evidence convincingly shows that the existing third berth is used and useful to TAPS and should be maintained. For example, in a December 2008 application to the RCA to decommission berths 1 and 3 for crude off loading purposes, the Owners stated that they intend “to continue using Berth 3.” They added that:

[a]part from loading crude oil, “Berth 3 is currently and frequently used and useful as a layover berth in various circumstances, as for example, when Hinchinbrook Entrance is closed due to adverse weather conditions in the Gulf of Alaska, for crew member medical evacuations, for vessel repairs, or in support of oil spill drills.”⁵⁰⁴

313. Alyeska employee Tom Stokes agreed that the third berth has been used occasionally at the VMT, such as when the VMT was forced to close down and the pipeline was required to go into proration because of bad weather.⁵⁰⁵

314. The Court finds that two loading berths and one lay berth should reasonably be considered part of the existing useful property as of each of the lien dates and included in the RCN.

315. The Pro Plus cost studies advanced for the years 2007 through 2009 use floating roof tanks, unlike the 2006 study.

⁵⁰² Tr. 4477, 6451-52 (Lloyd). Mr. Stokes, Alyeska employee, testified that there is no minimum throughput limitation for the existing VMT to function. Tr. 3453 (Stokes). Mr. Stokes further testified that none of the projects that are currently being considered at the VMT would impact the throughput or the availability of the facility. Tr. 3453 (Stokes).

⁵⁰³ Tr. 4355-56 (Lloyd); MUN7-9020; MUN7-1522 at 6.

⁵⁰⁴ MUN7-1522 at 6.

⁵⁰⁵ Tr. 3459-60 (Stokes). See also Allen Dep. at 26 (discussing bad weather in Valdez disrupting operations).

316. As in the 2006 ad valorem tax matter, Mr. Lloyd indicated that his VMT estimate is based on a 1.1 million bbl/d throughput. But he also considered new information as to the lower flow rates possible on the pipeline.⁵⁰⁶ In order to match the range of capacity of the pipeline, Mr. Lloyd changed his estimate to utilize internal floating roof tanks.⁵⁰⁷ Properly designed floating roof tanks will provide greater flexibility for throughputs of less than 1.1 million bbl/d.⁵⁰⁸

317. Mr. Lloyd testified that he maintains his concerns about using internal floating roof tanks in a severe seismic zone.⁵⁰⁹ As in the 2006 appeal, he again looked to the 2003 Tank Consultant, Inc. ("TCI")/Nyman Report.⁵¹⁰ These were consultants hired by Alyeska to evaluate the use of floating roof tanks at the VMT; their report has not been updated. Mr. Lloyd accounted for the cautions expressed in the TCI/Nyman report by limiting the operating volume of the tanks to approximately 430,000 barrels versus the stated capacity of 510,000 barrels in each of the existing tanks.⁵¹¹

318. But with the decreased tank volume, the needed number of tanks increased from the 15 tanks in operation at TAPS during the lien years to 18, including one spare.⁵¹² Mr. Lloyd's estimate provided sufficient storage for 6.6 days of throughput at 1.1 million bbl/d, with a total capacity of 7,222,000 barrels.⁵¹³ The total capacity of the existing 15 tanks is 7,650,000 barrels.⁵¹⁴

⁵⁰⁶ Tr. 4345-51 (Lloyd); MUN7-0008 at 27; MUN7-1553 at 6 (Section 5.2); MUN7-218 at 19.

⁵⁰⁷ Tr. 3721 (Ellwood); Tr. 4359-60 (Lloyd).

⁵⁰⁸ MUN7-0008 at 26.

⁵⁰⁹ Tr. 4363 (Lloyd).

⁵¹⁰ Tr. 4363-66, 4373-74 (Lloyd); MUN7-1552; MUN7-1508.

⁵¹¹ Tr. 4326-66 (Lloyd); MUN7-0008 at 31-32.

⁵¹² Tr. 4365-67 (Lloyd); Tr. 3454 (Stokes) MUN7-0008 at 31-32. *See also* MUN7-1519.

319. Mr. Stokes of Alyeska testified that during 2007 through 2009 there were 15 tanks in service at the VMT. He also confirmed that currently only 13 tanks are in actual use, with the two additional tanks undergoing cleaning and inspection.⁵¹⁵ A total of 18 tanks were originally constructed at the VMT. Mr. Stokes agreed that the additional three out-of-service tanks provide more flexibility to the Owners should a reason to put them back into service arise.⁵¹⁶

320. This Court finds that the Pro Plus tank design is a reasonable replacement for the existing TAPS tank design, and is reflective of the design capacity of the existing VMT, which is at least 1.42 million bbl/d. In fact, the existing VMT handled throughputs of 2.1 million bbl/d when all of its 18 tanks were in operation.

321. Pro Plus has estimated 10 million cubic yards of excavation will be needed to construct the VMT site.⁵¹⁷

322. Mr. Lloyd testified about the excavation work when the VMT was originally constructed. He explained that “the amount of material excavated in the Terminal had escalated from a planned 4 million cubic yards to approximately 15 million cubic yards.”⁵¹⁸ In any modern Greenfield development of the VMT site, the same soil conditions would be present as existed during the original construction.⁵¹⁹ As in the 2006 de novo trial, Mr. Lloyd persuasively testified at the current proceeding that it would be essential to fill behind

⁵¹³ MUN7-0008 at 32.

⁵¹⁴ MUN7-9023 at 333.

⁵¹⁵ Tr. 3454-55 (Stokes).

⁵¹⁶ Tr. 3458 (Stokes).

⁵¹⁷ Tr. 4358-59 (Lloyd).

⁵¹⁸ Tr. 4358; MUN7-1513.

⁵¹⁹ Tr. 4381-82 (Lloyd).

Jackson Point.⁵²⁰ Overall, this Court was persuaded that Pro Plus's estimated 10 million cubic yards of excavation is reasonable.

323. The Owners also critique Mr. Lloyd's VMT cost estimate because of the methodology of crewing up the work instead of using a "process estimation" methodology. Process estimation determines the building materials necessary, then uses an estimating manual to determine the man-hours for each item.⁵²¹ It is a common way for engineers to cost projects.⁵²² But Mr. Ellwood indicated the approach that Pro Plus used was commonly used by contractors, and that process estimation on the VMT was problematic because it is a one of a kind, unique property.⁵²³ On balance, this Court was not persuaded that Pro Plus's use of the crew-up method for estimating the cost of the VMT was unreasonable.

324. Pro Plus has estimated that the clearing and grading at the VMT would take 310 days.⁵²⁴ But this Court found persuasive Hawk's observation that this crew needs to be "done and gone to make the terrain available for other crews."⁵²⁵ And this Court concurred with Hawk's critique regarding the VMT camp. 450 days for VMT camp installation would appear excessive, while 78 workers at the camp, including 16 truck drivers and 24 laborers, as well as 28 pick-up trucks also appears excessive.⁵²⁶ Yet it bears noting that Hawk's revised estimate for the direct costs for the VMT totaled \$1.3 billion.⁵²⁷ In contrast, Stantec's

⁵²⁰ Tr. 4385-86 (Lloyd); MUN7-1535 to MUN7-1538.

⁵²¹ Tr. 3732-36 (Ellwood).

⁵²² Tr. 3732-33 (Ellwood).

⁵²³ Tr. 3734-35 (Ellwood).

⁵²⁴ MUN7-0008 at 544, 545.

⁵²⁵ TO-07-0044.0008. See also Owners' Proposed Findings of Fact and Conclusions of Law ¶ 390.

⁵²⁶ MUN7-0008 at 516, 555; TO-07-0044.0011.

⁵²⁷ TO-07-0044.0021

cost estimate for the VMT was higher – at 1.693 billion – even though Stantec had fewer tanks and far less proposed excavation.⁵²⁸

ii. Indirect Costs, Including Contingency

325. “Indirect costs are percentages that might be applied to all or some portion of the direct costs.”⁵²⁹ The indirect costs applied by Pro Plus include (1) project and construction management, engineering, and inspection, (2) owners’ costs, (3) ad valorem taxes and interest during construction, and (4) contingency. Each of these items is typically calculated as a percentage of direct costs associated with a project.

326. In 2006, the Division did not include any program manager costs in its RCN estimate.⁵³⁰ In its 2006 assessment, SARB determined there should be a program manager profit of 3% of direct costs.⁵³¹ Beginning in 2008, SARB adopted a project management fee of 7.5% that included construction management, engineering, and inspection in addition to the project management fee.⁵³² The Pro Plus cost estimate for the 2006 tax year and adopted by this Court in the Amended Decision included an allowance of 7.5% of its direct costs for all project management costs.⁵³³

\\

\\

\\

\\

⁵²⁸ TO-07-0021.0013.

⁵²⁹ Tr. 3741 (Ellwood).

⁵³⁰ MUN7-0235 at 11.

⁵³¹ Amended Decision ¶ 328.

⁵³² Amended Decision ¶ 328; MUN7-238 at 18 ($\$701,220,443/\$9,349,605,900 = 7.5\%$).

⁵³³ Amended Decision ¶ 333.

327. For tax years 2007 to 2009, Pro Plus again estimated program management costs at 7.5% of direct costs.⁵³⁴ The Court again finds that a project management fee of 7.5% is appropriate.

328. In 2008, SARB reduced Pro Plus's estimation of owners' costs from 10% to 5%.⁵³⁵ Mr. Ellwood, at the 2009 SARB hearing, testified why 10% was the appropriate allowance for these costs.⁵³⁶ In 2009, the Board agreed 10% was appropriate, stating that "[t]he Board found particularly persuasive the testimony from the Municipalities' witnesses on the importance, in a project like the TAPS, of having personnel from the owners to shadow contractor personnel and closely monitor the ongoing construction work in order to limit delays and cost-overruns."⁵³⁷

329. In this Court's Amended Decision for the 2006 tax year, Pro Plus's proposed owners' costs of 10% of direct costs were likewise adopted.⁵³⁸

330. In these proceedings, Pro Plus continues to maintain that 10% of direct costs appropriately measures owners' costs.⁵³⁹ The Court finds the percentages reasonable for the 2007 to 2009 tax years.

331. A replacement TAPS would be subject to ad valorem taxes during construction ("AVTDC").⁵⁴⁰ In the 2006 tax year trial, the "Pro Plus team used Mr. Greeley's method of

⁵³⁴ Tr. 3741 (Ellwood). Stantec similarly estimated engineering costs at 5% of direct construction costs for the main pipeline, and 12% for the pump stations and terminals. TO-07-0025.0684.

⁵³⁵ MUN7-0236 at 15, 17.

⁵³⁶ 2009 SARB Tr. 299-301 (Ellwood).

⁵³⁷ MUN7-0236 at 20.

⁵³⁸ Amended Decision ¶ 342.

⁵³⁹ Tr. 3741-42 (Ellwood). Stantec used a figure of 9% for owners' costs. Tr. 3274 (Fiske); TO-07-0025.684.

⁵⁴⁰ AS 43.56.060(e)(1); 15 AAC 56.110(b)(1).

calculating the ad valorem tax that had also been accepted by SARB.⁵⁴¹ The Court adopted that method as appropriate for determining the assessed value of TAPS for the 2006 tax year.⁵⁴²

332. In 2010, SARB determined that the Assessor's calculation required certain refinements to comply with Alaska law under 15 AAC 56.110(b)(1).⁵⁴³

333. In Alaska, the "full and true value" of an oil pipeline during construction is determined by the "actual cost incurred or accrued with respect to the property as of the date of assessment."⁵⁴⁴ The regulation that implements this portion of the statute explains how certain costs should be taxable as incurred, such as construction machinery, while those that relate to the entire project should be prorated over the time taken to complete the entire project.⁵⁴⁵

334. Pro Plus's AVTDC computation provided a breakdown between the two categories of costs – those that the regulation requires be accrued and those that are taxable as incurred – for each tax year.⁵⁴⁶ Based upon that breakdown, and applying the accrual schedule found in the example in 15 AAC 56.110(b)(1) over a seven year construction period, Pro Plus calculated the AVTDC at \$657,521,600 for 2007, \$721,816,800 for 2008, and \$713,929,600 for 2009.⁵⁴⁷ This Court finds that Pro Plus's method is consistent with the applicable regulation.

⁵⁴¹ Amended Decision ¶ 348 (internal citation omitted).

⁵⁴² Amended Decision ¶ 352.

⁵⁴³ MUN7-0237 at 30-32.

⁵⁴⁴ AS 43.56.060(e)(1).

⁵⁴⁵ 15 AAC 56.110(b)1)

⁵⁴⁶ MUN7-0008 at 39, 57, 588, 1119.

⁵⁴⁷ MUN7-0008 at 56, 587, 1118.

335. For the 2006 tax year, the Court previously concluded that Pro Plus's methodology for the inclusion of interest during construction ("IDC"), calculated based upon a percentage of project spending spread over a seven-year period and assuming 100% debt financing at a cost of 6%, was appropriate for determining the assessed value of TAPS.⁵⁴⁸ Consistent with that approach, Pro Plus's estimate for 2007, 2008 and 2009 included \$1,949,285,100, \$2,134,744,500, and \$2,114,060 for IDC, respectively.⁵⁴⁹ This Court finds that Pro Plus's method to calculate interest during construction is reasonable.

336. It is standard practice to include a contingency in a cost estimate to account for uncertainty about the actual cost. The Municipalities' expert Dr. Mark Cronshaw stated that the Association for the Advancement of Cost Engineering ("AAACE") defines contingency as "an amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs."⁵⁵⁰ The appropriate amount of contingency depends on the desired level of certainty that the actual cost of a project will not exceed the estimated cost.⁵⁵¹ As Dr. Cronshaw testified in the 2006 trial and again in these proceedings, a standard approach to determine contingency is the P50 or 50% level of confidence (i.e., the contingency amount that – when added to the base estimate – makes it equally likely that the project will actually cost more or less than the estimate).⁵⁵²

⁵⁴⁸ Amended Decision ¶¶ 350, 352.

⁵⁴⁹ MUN7-0008 at 55, 586, 1117.

⁵⁵⁰ Tr. 4675 (Cronshaw).

⁵⁵¹ Tr. 4684-85 (Cronshaw).

⁵⁵² Tr. 4695; 4699-4700 (Cronshaw). *See also* Tr. 3637-38 (Allison); Amended Decision ¶ 353.

337. In the 2006 trial, the Court determined a 25% contingency was appropriate.⁵⁵³ In 2007, the Department used an 8% contingency, which appears to have been adopted by SARB.⁵⁵⁴ In 2008, the Division reduced Pro Plus's proposed contingency factor from 25% to 20%. On review to SARB, the Board concluded that the contingency factor should be no more than 5%.⁵⁵⁵ In 2009, the Division used a 10% contingency factor, which the Board rejected as improper and instead employed a 25% contingency.⁵⁵⁶ This was in response to the additional information provided to SARB by Dr. Cronshaw and the Pro Plus team, which SARB found constituted the "most persuasive" evidence before the Board.⁵⁵⁷ SARB held "It was clear to the Board that based on their careful assessment of these risks, the 25% contingency factor in the 2009 Pro Plus cost study was justified."⁵⁵⁸

338. Dr. Cronshaw relied upon the AACE in preparing his opinion in this case. As explained by Dr. Cronshaw:

AACE describes five classes of estimate. Class 5 is a preliminary cost estimate that has a very wide range because of substantial uncertainty. Class 1 is a control estimate that's usually prepared for financial control purposes during a project, so after the detailed engineering has been completed and so on. And class 3 is something between.⁵⁵⁹

A conceptual study would have a relatively high contingency because the detailed design basis, engineering, and permitting would not yet have occurred, while a budgetary estimate

⁵⁵³ Amended Decision ¶¶ 366.

⁵⁵⁴ MUN7-0234 at 12.

⁵⁵⁵ MUN7-0235 at 18-20.

⁵⁵⁶ MUN7-0236 at 18.

⁵⁵⁷ MUN7-0236 at 19.

⁵⁵⁸ MUN7-0236 at 19.

⁵⁵⁹ Tr. 4719 (Cronshaw).

would employ a lower contingency if a detailed cost estimate had been prepared.⁵⁶⁰ The Pro Plus team determined that the RCN project would appropriately be labeled somewhere between a Class 3 and a Class 4.⁵⁶¹

339. The contingencies estimated by the parties in this case were substantially different. Experts for both the Municipalities (Dr. Mark Cronshaw) and the TAPS Owners (Mr. Jerald Allison) ran Monte Carlo analyses to model the uncertainty associated with the project to arrive at a contingency estimate for the TAPS RCN.

340. From his Monte Carlo analysis, Dr. Cronshaw concluded that contingencies of 36%, 39%, and 37% are the appropriate amounts for a P50 case for the Pro Plus study for years 2007, 2008, and 2009.⁵⁶²

341. The Court finds Dr. Cronshaw presented a comprehensive and well-documented contingency analysis consisting of extensive materials that were admitted into the record. He also carefully followed the recommended procedures of the AACE. Dr. Cronshaw verified the reasonableness of his Monte Carlo analysis by comparing his findings with the recommended AACE ranges.⁵⁶³ Although the AACE ranges apply strictly only to process facilities, the fact that Dr. Cronshaw's analysis was within the ranges provides a check on the reasonableness of his conclusions.⁵⁶⁴ Additionally, as discussed below, Dr.

⁵⁶⁰ Tr. 4718-19 (Cronshaw).

⁵⁶¹ Tr. 4719 (Cronshaw).

⁵⁶² Tr. 4679; 6331 (Cronshaw).

⁵⁶³ Tr. 4720 (Cronshaw).

⁵⁶⁴ Tr. 4720 (Cronshaw).

Cronshaw verified his analysis by comparing the contingency with cost overruns from numerous actual projects, including TAPS' projects, further validating his results.⁵⁶⁵

342. Although Dr. Cronshaw determined a substantially higher contingency was appropriate, Pro Plus, based on the experience and consensus of the team, chose a 25% contingency.⁵⁶⁶ Mr. Ellwood expressed his confidence in the number chosen by the Pro Plus team: "We think that's a very reasonable number. We have had many, many discussions amongst the team about what to do, and we have checked that number against what other corporations do; and we're all, I think, entirely comfortable with it. I know I am."⁵⁶⁷ Dr. Cronshaw estimated that Pro Plus's use of a 25% contingency meant there would be at least an 84% chance that the actual cost of the project would exceed Pro Plus's final cost estimate.⁵⁶⁸

343. The contingency adopted by Stantec for its 30-inch hypothetical pipeline, as calculated by Mr. Allison through his Monte Carlo analysis, was 3.3%, 3.4%, and 3.5% for tax years 2007, 2008, and 2009, respectively.⁵⁶⁹

344. At a theoretical level it appears that a major difference between the Stantec contingency and the Pro Plus contingency is that Stantec concluded the project had little or no uncertainty due to it being an estimate to build a replacement for TAPS as of fixed dates in the past.⁵⁷⁰ Stantec concluded that because much was known about TAPS today due to

⁵⁶⁵ Tr. 4725-27 (Cronshaw); 6314-15 (Cronshaw).

⁵⁶⁶ Tr. 3742 (Ellwood); 4680 (Cronshaw), 6331-32 (Cronshaw); 6496 (Tise).

⁵⁶⁷ Tr. 3742 (Ellwood).

⁵⁶⁸ Tr. 4680 (Cronshaw).

⁵⁶⁹ Tr. 3607-08 (Allison); 4752 (Cronshaw); 5762 (Karlik).

⁵⁷⁰ Tr. 5841-42 (Karlik).

it already having been constructed, there was minimal uncertainty in such items as the labor rates and the cost of obtaining such items as permits for construction, thus a contingency of approximately 3.5% was appropriate.⁵⁷¹ Yet the Stantec design is substantially different from the existing line with its smaller diameter, higher pressure line, single support VSMS and DRA with 80% drag reduction. Further, the Stantec design relies on freestanding thermosyphons and an extensive use of ice roads, both of which also differ from the original design and construction.⁵⁷² As Dr. Cronshaw concluded, “it seems curious to assert that the contingency for that different design [Stantec] would be much lower because one knows something about the existing 48” line.”⁵⁷³

345. Mr. Allison’s trial testimony on this topic conflicted with his deposition testimony.⁵⁷⁴ At trial Mr. Allison was asked, “[T]he fact that this was a replacement cost new was not a significant part of the debate in terms of the elicitation, was it?”⁵⁷⁵ Mr. Allison responded:

No, as a matter of fact, I think – I don’t think that’s correct. I think we did talk about that this is a replacement cost new . . . we talked about that the fourth quadrant is considerably smaller for an RCN . . . I know we talked about it when we discussed the fourth quadrant.⁵⁷⁶

But counsel then repeated the identical question that had been asked to Mr. Allison at his deposition. There, Mr. Allison, reading from his deposition testimony at trial, stated: “The fact that it was a replacement project had no impact on how the elicitation was done and

⁵⁷¹ Tr. 5761-62 (Karlik); 5796 (Karlik); 5841-42 (Karlik).

⁵⁷² Tr. 4751 (Cronshaw).

⁵⁷³ Tr. 4751 (Cronshaw).

⁵⁷⁴ Tr. 3631-32 (Allison).

⁵⁷⁵ Tr. 3627 (Allison).

⁵⁷⁶ Tr. 3627-28 (Allison).

how the number was derived whatsoever”⁵⁷⁷ On redirect, later at trial, counsel for the Owners asked Mr. Allison, “Did you explain, in your deposition, what you think the typical range of contingency is for a replacement cost estimate?”⁵⁷⁸ Inexplicably, Mr. Allison responded: “My recollection is that I would have expected it to be less than what it would be for a normal construction process.”⁵⁷⁹ Mr. Allison did not attempt to explain why his deposition testimony directly contradicted his testimony at trial.

346. An additional example of Mr. Allison’s unreliability as a witness was evidenced when he testified regarding a typical range for contingency. On direct he was asked, “Do you have in mind the typical range of contingency that you would expect for a replacement cost new estimate?”⁵⁸⁰ Mr. Allison responded: “Probably somewhere between 2 and 5 percent”⁵⁸¹ But on cross, counsel read a similar question asked of Mr. Allison during his deposition: “What would you think the typical range of contingency is for a replacement cost estimate in a study of the level and detail of the Stantec study?”⁵⁸² Mr. Allison testified at his deposition (as read at trial): “My answer is: I don’t have an opinion on a range of percentage estimate that would be correct, right, typical, or anything else for a replacement project because I’ve never done comparative studies and I’ve never read – anybody that did comparative studies.”⁵⁸³

⁵⁷⁷ Tr. 3631-32 (Allison).

⁵⁷⁸ Tr. 3657 (Allison).

⁵⁷⁹ Tr. 3657 (Allison).

⁵⁸⁰ Tr. 3657 (Allison).

⁵⁸¹ Tr. 3657 (Allison).

⁵⁸² Tr. 3660 (Allison).

⁵⁸³ Tr. 3660 (Allison).

347. Because of his inconsistent sworn statements, this Court finds Mr. Allison was not a credible witness. Rather, this Court concurs with Dr. Cronshaw's observation that Stantec's contingency was unreasonably low, particularly for a project at the conceptual stage only.⁵⁸⁴

348. Carlton Karlik also testified for the Owners about the appropriate contingency to be used in a TAPS RCN analysis. He testified that with an RCN, there is much less unknown about a project than a Greenfield original construction project, thus less risk is involved, and hence a lower contingency is appropriate.⁵⁸⁵ However, Mr. Hisey testifying for the Municipalities asserted that even a completed project carries a contingency of 2% to 3% to account for remaining unknowns such as startup, completion and potential litigation costs.⁵⁸⁶ To that end, Mr. Hisey testified that he has reviewed hundreds, if not thousands, of Alyeska funding authorizations ("AFEs"), and he has never seen a construction AFE with a contingency in the 3% to 4% range.⁵⁸⁷

349. Moreover, Charles Coulson, the President of BP Pipelines (Alaska) testified at his deposition in this case that he was unsure of the standard contingency for TAPS projects.⁵⁸⁸ But before FERC, Mr. Coulson testified that a 30% contingency at the outset of a project would be "normal." Before FERC he also testified, "When you get down to the

⁵⁸⁴ Tr. 4253 (Cronshaw).

⁵⁸⁵ Tr. 5759-62, 5840-41 (Karlik).

⁵⁸⁶ Tr. 4980 (Hisey).

⁵⁸⁷ Tr. 4978 (Hisey).

⁵⁸⁸ MUN7-0001 at 3879.

execute phase of a particular project, where the engineering design is completed, you'd expect the contingency to be much lower, five or ten percent in some cases."⁵⁸⁹

350. As in the 2006 tax year trial, Mr. Karlik did not determine a specific contingency.⁵⁹⁰ Instead he testified for the Owners that a range of 5% to 10% contingency was typical when doing a replacement cost new estimate (versus an original construction estimate).⁵⁹¹ But based on the totality of evidence presented on contingency, the Court again finds Mr. Karlik's testimony unpersuasive.⁵⁹²

351. Dr. Cronshaw thoroughly validated the reasonableness of the Pro Plus team's 25% contingency. In addition to performing his Monte Carlo analysis and comparing the range of his calculations to the AACE literature (as discussed above), he looked at cost overruns experienced by other megaprojects and at TAPS' specific projects.

352. Dr. Cronshaw testified regarding the MacKenzie Valley Project. In 2004, the project presented its cost estimate to the National Energy Board in Canada of \$3.8 billion, with a 28% contingency.⁵⁹³ By 2005, after project expenditures of \$600 million,⁵⁹⁴ the estimate had grown to \$7.8 billion, nearly doubling the estimate from the previous year.⁵⁹⁵

353. Additional examples offered by Dr. Cronshaw in support of his opinion included the Nord Stream Pipeline in the Baltic Sea.⁵⁹⁶ There, the cost estimate was €5 billion in

⁵⁸⁹ MUN7-0001 at 3879-80.

⁵⁹⁰ Amended Decision ¶ 358.

⁵⁹¹ Tr. 5762 (Karlik); 4750 (Cronshaw).

⁵⁹² Amended Decision ¶ 358.

⁵⁹³ Tr. 4725 (Cronshaw) (the figure includes a 5% risk allowance).

⁵⁹⁴ Tr. 6317-18 (Cronshaw).

⁵⁹⁵ MUN7-0010 at 44; Tr. 4723-24 (Cronshaw).

⁵⁹⁶ MUN7-0010 at 44, Tr. 4726 (Cronshaw).

2005, rising nearly 50% to €7.4 billion in 2008.⁵⁹⁷ Another example was the BTC pipeline from Azerbaijan to Turkey which was reported to have an expected 30% cost growth from its original estimate to nearly \$3 billion.⁵⁹⁸ While some of the cost overruns in the above mentioned projects may be attributable to changes in scope, overall these examples supported Dr. Cronshaw's opinion that historically, large-scale projects experience notable cost growth.

354. Regarding the Denali Gasline, after \$135 million had been invested to develop a cost estimate, Mr. Coulson indicated the contingency for the project was "in the neighborhood of 30%."⁵⁹⁹

355. Dr. Cronshaw persuasively opined that TAPS' own projects also support a 25% contingency as the minimum appropriate contingency to achieve a proper assessed valuation of TAPS. Dr. Cronshaw referred to an Aerospace Corporation report dated July 1977 which indicated that as of mid-1974, the expected cost to complete TAPS was \$4.088 billion.⁶⁰⁰ By that point, significant components of the project were already in place: the pipe had been purchased, haul roads had been constructed, project labor agreements had been signed, the Federal "Alaska Pipeline Act" had been passed, contractors such as Bechtel and Fluor had been retained, and other key contracts had been assigned.⁶⁰¹ Three years later, in 1977, the actual project cost was \$7.815 billion – nearly double the 1974 estimate.⁶⁰²

⁵⁹⁷ MUN7-0010 at 44; Tr. 4726 (Cronshaw).

⁵⁹⁸ MUN7-0010 at 44; Tr. 4727 (Cronshaw).

⁵⁹⁹ Coulson Dep. 167-68; MUN7-0001 at 3877.

⁶⁰⁰ MUN7-1151 at 12. The original estimate from 1969 indicated in that exhibit was under \$1 billion.

⁶⁰¹ MUN7-2554 at 47-48; Tr. 4731 (Cronshaw).

⁶⁰² Tr. 4731 (Cronshaw).

356. Another real-world example supporting a contingency substantially higher than that offered by the Owners relates to SR. As part of discovery, the Owners provided certain AFEs related to the Owners' budgetary approval of SR of TAPS. In March 2004, the Owners authorized SR in the amount of \$233 million (after \$10 million had already been spent on engineering).⁶⁰³ In 2005, Alyeska prepared supplemental AFEs seeking approval of an additional \$168.2 million to complete SR.⁶⁰⁴ Then, in 2007, Alyeska submitted supplemental AFEs for additional expenditures that raised the cost of completing SR to \$696 million, or about a 185% cost overrun.⁶⁰⁵ Moreover, the 2007 supplemental AFE included an 18.5% contingency – after much of the SR had already been completed and substantial cost overruns already incurred.⁶⁰⁶ In reviewing the AFEs, Dr. Cronshaw also noted that the extensive cost overruns were not attributable to a change in scope but rather design development issues.⁶⁰⁷

357. Dr. Cronshaw also referred to a 2005 Fluor Cost Study to support his opinion that a 25% contingency is reasonable. The study was prepared for the Owners for FERC ratemaking proceedings to set out the cost for the dismantling and removal of TAPS. The 2005 Fluor updated cost estimate included a 25% contingency which Fluor stated: "is consistent with the contingency factor used in the 1983 estimate."⁶⁰⁸ Alyeska later prepared

⁶⁰³ Tr. 4733 (Cronshaw).

⁶⁰⁴ Tr. 4734 (Cronshaw).

⁶⁰⁵ Tr. 4737 (Cronshaw).

⁶⁰⁶ Tr. 4737 (Cronshaw); MUN7-0011 at 2-3.

⁶⁰⁷ Tr. 4735 (Cronshaw).

⁶⁰⁸ MUN7-2569 at 4; Tr. 4739-40 (Cronshaw).

a 2007 update to the Fluor study which also used a 25% contingency for all but a few cost categories (e.g., the contingency for the VMT was 22%).⁶⁰⁹

358. A 2010 study of the cost of heaters to operate TAPS at declining throughput levels prepared by Larkspur Associates, LLC (“Larkspur”) for BP Pipelines also validates a contingency of no less than 25%. The study was a detailed estimate of the cost of all the heater facilities by location along the pipeline that may be necessary to operate TAPS down to 100,000 bbl/d. As to contingency, the report stated,

The conceptual estimates include contingency at 40 percent based on an accuracy range of +35% / -20% as reviewed and determined based on AACE published documentation (see attached). Based on the process information and quantities presented, estimate approach and experience of the project team we recognize that there has been very little design work done to date to reflect a lower percentage or a tighter accuracy range.⁶¹⁰

359. Larkspur further supported its 40% contingency by noting that although the project was in an early stage, there was a significant amount of known cost information: “Based on the approach used in developing the costs which are based on a significant amount of historical project information and current actual cost information we believe the estimates are between a Class 3 – 4 as published by AACE.”⁶¹¹ The Pro Plus team also considered its TAPS’ RCN a Class 3 to 4 project, yet utilized a lesser contingency of 25%.⁶¹²

360. The Larkspur study also points out that, “Several sites (MP 31, MP 39, MP 75, MP 178, MP 211, MP 629) not currently corresponding to an existing pump station or

⁶⁰⁹ MUN7-2568 at 17; Tr. 4740-41 (Cronshaw).

⁶¹⁰ MUN7-3044 at 19.

⁶¹¹ MUN7-3044 at 19.

⁶¹² Tr. 4717-19 (Cronshaw).

developed site location are required”⁶¹³ The study specifically refers to those sites as “Greenfield.”⁶¹⁴ But where heater facilities are costed for installation at existing sites the study calls them “Brownfield.”⁶¹⁵ Yet for both Greenfield and Brownfield locations, Larkspur uses the same 40% contingency.⁶¹⁶ This is at odds with Mr. Karlik’s unsupported assertion that “RCN estimates require less contingency than Greenfield new ventures.”⁶¹⁷

361. These validations, in addition to Dr. Cronshaw’s rigorous Monte Carlo modeling and associated analysis, fully persuade the Court that the 25% contingency employed by Pro Plus is reasonable for a RCN of TAPS. Further, based upon the evidence presented at the trial de novo, the Court finds that a contingency of less than 25% would result in an improper valuation of TAPS for the three years at issue.

4. Conclusion of the RCN of TAPS

362. Both the Owners and the Municipalities submitted extensive cost studies and provided detailed testimony regarding each of the proposed replacement TAPS.

363. For the reasons set forth above, this Court has concluded that the Stantec pipeline is not an appropriate design to use as the basis for the application of the cost approach in the valuation of TAPS.

364. Overall, the Pro Plus RCN is an appropriate RCN to use as the basis for the application of the cost approach. Throughout this litigation, Pro Plus experts have strived to

⁶¹³ MUN7-3044 at 4.

⁶¹⁴ MUN7-3044 at 7-10, 13.

⁶¹⁵ MUN7-3044 at 9.

⁶¹⁶ See, e.g., MUN7-3044 at 8 and 38 (MP 39 Greenfield at 40%) versus MUN7-3044 at 9 and 49 (PS 3 Brownfield also at 40%).

⁶¹⁷ TO-07-0046 at 2.

thoroughly answer questions posed by the Court and on cross-examination.⁶¹⁸ Conversely, the Stantec experts were unable to answer numerous questions about the details of their cost estimate on cross-examination.⁶¹⁹

365. Overall, this Court finds that the Pro Plus cost estimates are reliable. However, as set forth above, this Court has identified several concerns with the Pro Plus cost estimates. It is neither necessary nor feasible to make a precise adjustment in the Pro Plus RCNs to account for each of these concerns – the goal of an RCN, in any event, is to arrive at an estimate of the cost of replacing TAPS with a modern day equivalent of similar quality and like utility – not a precise amount. But this Court does find that some adjustment to the Pro Plus RCN is warranted to account for the concerns that have been identified in the preceding findings. Based upon this Court's consideration of all the evidence, the Court finds that a 10% reduction in Pro Plus's RCN cost estimates for each of the lien years is warranted to arrive at amounts that this Court has determined would better reflect the estimated cost to replace TAPS in each of the lien years with a new pipeline transportation system of similar quality and like utility.

366. The Owners asserted that the RCNs should be compared to the cost estimates that were prepared for the Denali pipeline and Trans Canada gas pipeline project. But due to confidentiality restrictions, no witness was able to provide detailed testimony to this Court about either of those cost estimates. As a result, this Court did not accord weight to either of

⁶¹⁸ See, e.g., Tr. 3725-26, 3737-38, 3742, 3764-65, 3777-78, 3858-59, 3870, 3949, 6698-99 (Ellwood); Tr. 4440, 4461, 4471, 4473-74, 4484-85, 4511-13, 4516-17, 4632-33, 6612 (Steindorff); Tr. 4954-55, 4961-64, 4968, 4979, 4983, 5060, 6368 (Hisey) (sealed); Tr. 3898-4057 (Ellwood); Tr. 4178-4245 (Tise); Tr. 4394-4424 (Lloyd); Tr. 4518-74, 4608-31 (Steindorff).

⁶¹⁹ See, e.g., Tr. 3314-15, 3327-28, 3329-30, 3331-32, 3330, 3337-38, 3341-42, 3359, 3363-64 (Fiske); Tr. 2511-16, 2516-18, 2520-22, 2532-33, 2538, 2541, 2542, 2543 (Rein).

those cost estimates, while recognizing that, had confidentiality issues been addressed, the information in those estimates could have been quite helpful for comparison purposes.

367. The 2007, 2008 and 2009 RCN cost estimates advanced by Pro Plus were \$19.606 billion for 2007, \$21.471 billion for 2008, and \$21.263 billion for 2009. Reducing each of these amounts by 10% results in the following determinations by this Court of the Replacement Cost New for TAPS for each of the tax years at issue:

2007	\$17.645 billion
2008	\$19.324 billion
2009	\$19.137 billion

B. Depreciation

1. Methods of Calculating Depreciation

368. Once the RCN is determined, the appraisal analysis requires a calculation of the amount of depreciation. "Depreciation is the difference between the contributory value of an improvement and its cost at the time of appraisal."⁶²⁰ The three types of depreciation traditionally recognized by appraisers are physical deterioration, functional obsolescence, and economic obsolescence.⁶²¹ The traditional definitions of these terms are:

Physical deterioration is the loss in value or usefulness of a property due to the using up or expiration of its useful life caused by wear and tear, deterioration, exposure to various elements, physical stresses, and similar factors.

Functional obsolescence is the loss in value or usefulness of a property caused by inefficiencies or inadequacies of the property itself, when compared to a more efficient or less costly replacement property that new technology has developed.

⁶²⁰ *The Appraisal of Real Estate* at 391.

⁶²¹ *Valuing Machinery and Equipment* at 43; *The Appraisal of Real Estate* at 391-92; Tr. 11251-52 (Podwalny).

Economic obsolescence (sometimes called "external obsolescence") is the loss of value of a property by factors external to the property. These may include such things as the economics of the industry; availability of financing; loss of material and/or labor sources; passage of new legislation; changes in ordinances; increased cost of raw materials, labor, or utilities (without an offsetting increase in product price); reduced demand for the product; increased competition; inflation or high interest rates; or similar factors.⁶²²

369. The three principal methods for estimating depreciation are: (1) the market extraction method; (2) the economic age-life method; and (3) the breakdown method.⁶²³ The market extraction method and the economic age-life method are the primary methods used by most appraisers to estimate the total depreciation in a property; each is "applied to the whole property and are easier to understand and use."⁶²⁴

370. In its simplest form, the economic age-life method considers all three forms of depreciation using a single calculation.

371. The market extraction method relies upon the availability of comparable sales from which depreciation can be extracted.⁶²⁵ In the case of TAPS, direct comparable sales information is not available, so that method is not appropriate.⁶²⁶

372. The breakdown method of depreciation calculates each form of depreciation (physical, functional, and economic) separately.⁶²⁷ The breakdown method "is primarily used when the appraisal assignment requires that each form of depreciation be accounted

⁶²² *Valuing Machinery and Equipment* at 67. See also *The Appraisal of Real Estate* at 391-92; Amended Decision ¶¶ 378.

⁶²³ *The Appraisal of Real Estate* at 409.

⁶²⁴ *The Appraisal of Real Estate* at 409.

⁶²⁵ *The Appraisal of Real Estate* at 416.

⁶²⁶ Tr. 12349 (Connolly).

⁶²⁷ *The Appraisal of Real Estate* at 424.

for in the appraisal report,⁶²⁸ and is “used when the market extraction and economic age-life methods cannot be applied.”⁶²⁹ The Owners’ appraiser Michael Remsha used this method.

373. The Court was not persuaded by Mr. Remsha’s application of the breakdown method to depreciate TAPS. Mr. Remsha opined that TAPS was 60% physically depreciated each of the tax years at issue.⁶³⁰ As part of his calculation, and despite new SR pumps being installed during the lien years, he concluded that the weighted chronological age of TAPS’ pumps was 29 years, and that their entire service life was 35 years – such that the newly installed pumps had only 6 years of life remaining by his calculations during each of the three lien years.⁶³¹ Given the recent \$700 million in SR investment, Mr. Remsha’s determinations in this regard were not credible.

374. Mr. Remsha also quantified an inutility penalty for TAPS based upon a projection of future inutility of the 30-inch Stantec pipeline.⁶³² But during the lien years, the 30-inch Stantec pipeline would be operating well over any reasonable maximum capacity for a 30-inch pipeline such that use of a future projection of unused capacity based on the maximum design capacity that Stantec asserted for its 30-inch pipeline is unwarranted. Moreover, the 30-inch pipeline is quite different from TAPS and may not reasonably be used as a standard to determine TAPS’ depreciation.

375. Another concern with Mr. Remsha’s approach is that with his breakdown method, TAPS is worth more when he assumed it could no longer transport oil below a

⁶²⁸ *The Appraisal of Real Estate* at 425.

⁶²⁹ *The Appraisal of Real Estate* at 425.

⁶³⁰ TO-07-0004.0253.

⁶³¹ TO-07-0004.0253.

⁶³² TO-07-0004.0079-88 (projected future inutility used as a basis for deduction from the current economic value of TAPS).

300,000 bbl/d throughput than it would be worth if it could transport oil down to 200,000 bbl/d.⁶³³ This illogical result indicates a major flaw in Mr. Remsha's depreciation methodology.

376. For the foregoing reasons, this Court did not apply the breakdown method to depreciate TAPS.

377. In addition to the standard depreciation approaches, this Court also considered the use of a units-of-production method to depreciate TAPS. This method is more typically employed in depreciation for accounting purposes, not appraisal depreciation.⁶³⁴ "This method places emphasis on the total units to be produced and the rate of production. It takes into consideration the service life of an asset and thereby permits exhaustion of natural resources to be taken into account."⁶³⁵ The units-of-production approach has also been termed "the life-of-the-reserves" depreciation methodology because the valuation is "based on the estimated reserves of the system rather than the calendar years that those reserves are estimated to be in production."⁶³⁶

378. The Municipalities assert that "unit-of-production depreciation would not consider reserves growth and tend to overstate depreciation."⁶³⁷ Yet the applicable statute directs valuation "based on the estimated life of the proven reserves of gas and unrefined oil

⁶³³ See TO-07-0004.0249. Indicated value was \$2.2 billion with 200,000 bbl/d mechanical throughput limitation, and \$2.3 billion with 300,000 bbl/d mechanical throughput limitation.

⁶³⁴ *Valuing Machinery and Equipment* at 406.

⁶³⁵ *South Dakota Public Utilities Commission v. Federal Energy Regulatory Commission*, 668 F. 2d 333, 335, n.2 (8th Cir. 1982).

⁶³⁶ *Natural Gas Clearinghouse v. Fed. Energy Regulatory Comm'n*, 965 F. 2d 1066, 1070 n.5 (D.C. Cir. 1992).

⁶³⁷ Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 611.

then technically, economically, and legally deliverable into the transportation facility”⁶³⁸ — not valuation based on future oil and gas that may become proven reserves at some time in the future, but are not proven reserves as of the valuation date. Particularly where this Court has determined that the RCN should include the full utility of the TAPS’ 48-inch pipeline’s ability to transport up to 2.1 million bbl/d, the units-of-production approach might better capture the full degree of obsolescence that the property currently has by incorporating the proven reserves as of the lien dates into the valuation more precisely than the economic age-life method.

379. Roger Marks noted that the units-of-production approach had been used under the TAPS Settlement Methodology for TAPS’ tariffs for many years, and that under that methodology the original rate base was fully depreciated by the end of the 1990s.⁶³⁹ In his view, extending TAPS’ economic life for additional decades on a straight line basis using the economic age-life method would effectively take “most of those previously depreciated costs and deem . . . them un-depreciated again, which again, reduces the RCN adjustment and increases the ad valorem tax.”⁶⁴⁰ This argument was not persuasive to the Court, as the “value” of the asset for rate-making purposes is not related to its “full and true value” as defined by AS 43.56.060(e) for ad valorem tax purposes.⁶⁴¹ This Court was more persuaded by Mr. Marks’ additional argument that “depreciation depicts . . . the decline of the service potential... and the argument for units of production economically is that . . . for an asset like a pipeline, it more accurately mirrors...how the asset was used over its

⁶³⁸ AS 43.56.060(e)(2)

⁶³⁹ Tr. 12127, 12147 (Marks).

⁶⁴⁰ Tr. 12147 (Marks).

⁶⁴¹ See also Municipalities’ Proposed Findings of Fact and Conclusions of Law ¶ 603.

life”⁶⁴² Thus, the approach recognizes that the economic value of TAPS was considerably higher in 1988, when the average daily throughput was over 2 million bbl/d,⁶⁴³ than it will be in 2070, when the Municipalities estimate that total ANS production of current proven reserves will be less than 100,000 bbl/d.

380. Under a units-of-production approach, in the event that additional reserves are proven on the ANS in the future, then the value of TAPS for ad valorem tax purposes would increase based upon those additional reserves.

381. This Court finds that the legislative history, while inconclusive, indicates that the Legislature was aware of the units-of-production approach and did not specifically reject it when valuing pipeline property for ad valorem tax purposes. For example, at an October 1973 House Finance committee meeting, Homer Burrell addressed each of the sections of HB1. His description of the depreciation method for pipeline property appears to be a units-of-production approach:

Pipeline and pipeline equipment. [It] is depreciated on the economic life except in the event the physical life is different. Taking a \$4 billion installation as the cost with production high in the initial years, it would decrease rather steeply and then level off as production levels off. It will depreciate to probably half value during the first ten years, and is to the oil companies' advantage. However, if more oil is discovered (assuming the pipeline has an unlimited physical life) the line would again increase and flatten out, depending on how much oil is discovered.⁶⁴⁴

⁶⁴² Tr. 12151 (Marks).

⁶⁴³ TO-07-0004.0027.

⁶⁴⁴ *Minutes* at 50, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973) [2007 R. 9736]. In an ensuing paragraph of the minutes, Mr. Burrell is quoted as stating “the pipeline is not depreciated on units of production but on straight line.” From the context of that statement, however, it appears that he was referring there to the use of straight line depreciation that is explicitly referenced in the second portion of the statute that would apply only in the event that “too much line is built and oil is depleted” – i.e., “when the production rate is low.” *Id.* at 9736. Cf. Municipalities’ Proposed Finding ¶ 606.

382. AS 43.56.060(e)(2) explicitly directs the use of “straight line depreciation” only for those pipelines that have an economic life that is materially shorter than the estimated physical life. Arguably, this demonstrates that the Legislature was well aware of the concept of straight line depreciation and decided not to mandate its use for pipelines in operation such as TAPS.

383. The total barrels of oil transported on TAPS from the date of the pipeline’s inception up to each of the lien dates was as follows:⁶⁴⁵

January 1, 2007: 15,278,153,140

January 1, 2008: 15,548,315,190

January 1, 2009: 15,805,814,856

384. Based on this Court’s conclusion that the proven reserves on the ANS are between 7 and 8 billion barrels during the lien years, as discussed herein, a units-of-production depreciation methodology would result in a determination that TAPS was currently approximately two-thirds depreciated during the lien years.

385. While this Court has given careful consideration to a units-of-production approach, this Court finds that the Division and SARB should be accorded the first opportunity to consider its potential applicability to the depreciation of TAPS. The approach is not necessarily a standard appraisal methodology.⁶⁴⁶ And it is clear that the economic age-life analysis applied by the Division and the Board during each of the lien years is a standard methodology. Stated differently, this Court does not find that the Board’s lack of

⁶⁴⁵ TO-07-0004 at 260, 338, 408.

⁶⁴⁶ See 15 AAC 56.110(c).

reliance on a units-of-production depreciation methodology constituted a fundamentally wrong principle of valuation.

386. The economic age-life method was used by the Division and SARB for the lien years at issue, with additional depreciation deductions for functional and external obsolescence.⁶⁴⁷ The Court also applied a modified economic age-life method for the 2006 lien year.⁶⁴⁸

387. In the economic age-life method, depreciation is estimated by calculating the ratio between the effective age of the property and its economic life expectancy using the following formula:

$$[\text{Effective Age} / \text{Total Economic Life}] \times \text{Total Cost} = \text{Depreciation.}^{649}$$

388. Economic useful life is the “estimated period of time that a new property may be profitably used for the purpose for which it was intended.”⁶⁵⁰ In estimating a property’s economic life, “[a]ll aspects of a property and its market, including the quality and condition of the construction, the functional utility of the improvements, and market and locational externalities must be considered.”⁶⁵¹ “An improvement’s total economic life begins when it is built and ends when the improvement no longer contributes value for the use to which it was originally intended and is no longer the highest and best use of the underlying land.”⁶⁵²

⁶⁴⁷ MUN7-0234 at 6.

⁶⁴⁸ Amended Decision ¶¶ 386, 421.

⁶⁴⁹ *The Appraisal of Real Estate* at 420; *Valuing Machinery and Equipment* at 81-82. See also Amended Decision ¶ 380.

⁶⁵⁰ *Valuing Machinery and Equipment* at 565.

⁶⁵¹ *The Appraisal of Real Estate* at 413.

⁶⁵² *The Appraisal of Real Estate* at 412.

389. In the case of TAPS, AS 43.56.060(e)(2) requires the Court to determine its economic value based upon the estimated life of the proven reserves that are then technically, economically, and legally deliverable into the pipeline as of the lien date. Thus, under the statute, these proven reserves serve as a proxy for the economic life of the pipeline for ad valorem tax purposes.

390. The economic age-life method is “limited in that [it] typically reflect[s] a straight line pattern of depreciation.”⁶⁵³ As explained in *The Appraisal of Real Estate*, “this method assumes that every building depreciates on a straight-line basis over the course of its economic life. The straight-line pattern is only an approximation of the total depreciation of a property at a specific point in time.”⁶⁵⁴

391. The economic age-life method requires a determination of the “life of the line” – meaning the precise year in the future that TAPS will no longer transport proven reserves. Without a scaling adjustment, the approach can lead to an overestimation of the value of pipeline property that transports declining proven reserves. By way of example, the Municipalities’ appraiser Mr. Podwalny assumed that TAPS’ economic end-of-life on January 1, 2007 would be December 31, 2067.⁶⁵⁵ Based on that assumption, and using the Pro Plus RCN, he determined that the value of TAPS was \$12.893 billion as of that lien date.⁶⁵⁶ But in their proposed Findings, the Municipalities advocate an end-of-life date for TAPS of 2075 – eight years later than Mr. Podwalny had assumed.⁶⁵⁷ Making just that one change adjusts

⁶⁵³ *The Appraisal of Real Estate* at 421.

⁶⁵⁴ *The Appraisal of Real Estate* at 421.

⁶⁵⁵ MUN07-0035 at 28.

⁶⁵⁶ MUN07-0035 at 51.

⁶⁵⁷ Municipalities’ Proposed Findings of Fact and Conclusions of Law ¶ 893.

the value of TAPS to \$13.689 billion – an increase of nearly \$800 million– or approximately 6% – over Mr. Podwalny’s valuation based solely on this eight year adjustment over 50 years off into the future. In the Court’s view, this demonstrates that an exclusive reliance on straight-line economic age-life depreciation without scaling does not accord “due regard to the economic value of the property based on the estimated life of the proven reserves.”⁶⁵⁸ This is particularly true when it is undisputed that oil reservoirs typically have long tails of production, meaning that their production typically falls off fairly sharply after several years and then continues at a relatively low rate of production for many, many years thereafter.

392. This Court finds that SARB’s reliance on the economic age-life method with appropriate modifications to include all functional and external obsolescence was not the application of a fundamentally wrong principle of valuation. Further, application of that methodology has been fully supported by the extensive evidence presented to this Court at the trial de novo.

2. Life of the Line

393. Application of the economic age-life method to depreciate TAPS requires a determination of TAPS’ minimum throughput capacity, as well as a determination of the estimated life of the remaining proven reserves on the ANS.

a. Minimum Throughput Capacity

394. AS 43.56.060(e)(2) requires the Court to consider the estimated life of proven reserves “technically, economically, and legally deliverable *into* the transportation facility.” (emphasis added) The statute does not expressly require the Court to consider the

⁶⁵⁸ AS 43.56.060(e)(2).

transportation facility's hydraulic, mechanical, or operational capacity to transport all of those proven reserves.

395. The Municipalities argue that consideration of the pipeline's ability to transport all of those reserves that are deliverable is "an exhaustive and unnecessary exercise."⁶⁵⁹ They also assert that the Legislature's use of proven reserves as the proxy for the economic life of TAPS tends to understate the actual economic life of TAPS, and that to impose an additional minimum throughput limit would compound this understatement of the pipeline's actual economic life. The Municipalities also assert that common sense and expert testimony demonstrate no otherwise economic pipeline has shut down at 100,000 bbl/d, 50,000 bbl/d, or below.⁶⁶⁰ At trial, many expert witnesses testified they were unaware of any pipeline that had suspended transportation service for oil that was otherwise economic to produce due to mechanical, hydraulic or operational limitations of the pipeline.⁶⁶¹

396. Randy Hoffbeck, the former Assessor, testified that TAPS has been the only pipeline in Alaska that has been assessed using a minimum throughput capacity determination.⁶⁶² All other pipelines use the economic life of the proven reserves to determine the pipeline's value, without regard to the hydraulic, mechanical, or operational characteristics of the pipeline.⁶⁶³

⁶⁵⁹ Municipalities' Proposed Findings of Fact and Conclusions of Law at ¶ 613.

⁶⁶⁰ Tr. 5130-31 (Riordan); Tr. 8266-68 (Cicchetti); Tr. 11895 (Remsha).

⁶⁶¹ Tr. 674, 11895 (Remsha); Tr. 5130-31 (Riordan); Tr. 8266-68 (quoting Coulson Dep.); Tr. 9218 (Malvick); Tr. 11090 (McDevitt).

⁶⁶² Tr. 11565 (Hoffbeck).

⁶⁶³ Tr. 11565 (Hoffbeck).

397. The Assessor has interpreted the statute to require a minimum throughput determination.⁶⁶⁴ In this regard, the Assessor testified that “the idea is that it is not a reserve that can’t get transported to market and it won’t get delivered to the facility if the facility can’t transport it as of the lien date.”⁶⁶⁵ The Owners concur that a determination should be made as to TAPS’ minimum throughput capacity for ad valorem tax purposes.⁶⁶⁶ SARB has adopted this approach during each of the lien years.

398. This Court finds that SARB’s interpretation of the statute to require a minimum throughput determination is reasonable and will be applied by this Court. There is likely a minimum throughput level at which point crude oil will no longer be transportable on TAPS. Thus, an owner of a pipeline may seek to demonstrate by a preponderance of the evidence that there is a specified minimum throughput limit that impacts the amount of proven reserves that are technically deliverable into the pipeline as of the lien date.

399. In 2006, the Assessor determined that the minimum throughput of TAPS was 200,000 bbl/d or less, which the Board adopted for subsequent tax years and this Court also adopted in its Amended Decision for the 2006 tax year.⁶⁶⁷

400. At the trial for the 2007 through 2009 tax years, the Assessor advanced 150,000 bbl/d as TAPS’ minimum throughput.⁶⁶⁸ The Owners have asserted that TAPS will be unable to transport oil “when TAPS throughput at Pump Station 1 reaches between

⁶⁶⁴ See, e.g., MUN7-0236 at 23-24.

⁶⁶⁵ Tr. 8716-17 (Greeley).

⁶⁶⁶ See, e.g., Owners’ Proposed Findings of Fact and Conclusions of Law ¶¶ 422-543.

⁶⁶⁷ MUN7-0233 to MUN7-0238; Amended Decision ¶¶ 389 – 390.

⁶⁶⁸ Tr. 8717-20 (Greeley).

350,000 and 300,000 barrels per day.”⁶⁶⁹ The Municipalities have asserted that if a minimum throughput limitation is applied, that “more likely than not, TAPS will operate at least until flow becomes laminar (non-turbulent) at 40,000 to 50,000 bbl/d.”⁶⁷⁰

401. The Municipalities’ expert Dr. Jerry Modisette testified that there is no hydraulic or mechanical minimum throughput limit because the pipeline will be within pressure constraints at flows down to zero and the pump rate can also go down to zero through reducing pumps, throttling, and recirculation.⁶⁷¹ Former Alyeska Chief Operating Officer Dan Hisey concurred that there is no hydraulic or mechanical minimum throughput limit on TAPS.⁶⁷² The Owners’ expert, Ulli Pietsch, also testified that there is no hydraulic or mechanical reason that TAPS cannot operate down to 50,000 bbl/d.⁶⁷³ The inquiry therefore turns to whether there is an operational constraint that would prevent TAPS from transporting oil at some minimum capacity limit.

402. When an upstream oil production company books its proven reserves to the Securities Exchange Commission (“SEC”), it needs to perform an economic analysis to determine the financial feasibility of bringing the oil to market. One determinant in this process is the projected tariff rate to transport the oil on TAPS. In making that determination, an upstream ANS producer needs to make an assumption about TAPS’ minimum throughput capacity so that the cost of transportation per barrel can be computed. The effect of a lower throughput capacity increases the total amount of proven reserves

⁶⁶⁹ Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 535.

⁶⁷⁰ Municipalities’ Proposed Findings of Fact and Conclusions of Law ¶ 617.

⁶⁷¹ Tr. 9007-12 (Modisette).

⁶⁷² Tr. 8825-26 (Hisey).

⁶⁷³ Tr. 2024-25 (Pietsch).

expected to be transported through TAPS, thereby decreasing the tariff on a per-barrel basis and extending the economic life of the oil fields.

403. Until approximately 2004, BP used 300,000 bbl/d as the minimum throughput capacity of TAPS for purposes of booking its Alaska North Slope SEC reserves.⁶⁷⁴ At that point, BP began to consider whether the new variable speed pumps and recirculation piping associated with SR would permit the adoption of a substantially lower limit (and thus the booking of more reserves).

404. BPPA analyst John Haines testified at the trial in this case. In an email dated November 5, 2004, Mr. Haines stated:

Momentum is starting to grow around booking more reserves based on an updated view of TAPS' minimum achievable rates . . . Lastly, when TAPS rates reach 100 MBD [100,000 bbl/d] we stop. Our consultant thinks we can probably operate TAPS below this minimum rate, but we didn't want to push it any further at this time.⁶⁷⁵

405. [CONFIDENTIAL – SEE SEALED ENVELOPE.] 





⁶⁷⁴ MUN7-4406; MUN7-3046 at 1.

⁶⁷⁵ MUN7-9094 at 1, 2 (confidentiality waived on record at Tr. 11421).



406. In 2004, BP Pipelines retained JTG Technology Consortium to conduct a study to revisit the minimum throughput limit on TAPS. The 308-page JTG report was completed in 2005 (“JTG Study”) and concluded that “the low flow limit of the existing 48-inch TAPS pipeline was determined to be a PS [Pump Station] 1 rate of 135 MB/day [135,000 bbl/d].”⁶⁷⁷

407. The 135,000 bbl/d minimum throughput level set forth in the 2005 JTG Study was to be achieved with the addition of heat, although the study also allowed for other necessary modifications such as additional booster pumps, scraper trap valves, and piping for pigging.⁶⁷⁸ Ulli Pietsch, the Owners’ hydraulics expert in this trial, conducted the pressure and temperature simulations for the JTG Study.⁶⁷⁹

408. BPPA and its affiliates relied upon the JTG Study’s conclusion of a 135,000 bbl/d low-flow limit to create tariff profiles that BP then used to report its reserves for several years to the SEC.⁶⁸⁰



⁶⁷⁷ MUN7-3000 at 6.

⁶⁷⁸ MUN7-3000 at 33, 75, 80.

⁶⁷⁹ Tr. 2043-44, 2046 (Pietsch).

⁶⁸⁰ Tr. 11413-17 (Haines).

409. In its initial year-end 2004 reserves submission to the BP London office, which was scheduled a couple of months before the JTG Study was concluded, BP Exploration and BP Pipelines personnel determined “an effective TAPS minimum throughput level of 150,000 bbl/d at 2053,” using “conservative assumptions.”⁶⁸¹ The report added:

In the case of GPB [Greater Prudhoe Bay] and KRU [Kuparuk River Unit] (the biggest contributors to the reserves adds) each of these fields were still cash flow positive at 2064 (end of our tariff profile). The reserves coordinators arbitrarily chose to cut-off life at the earlier dates (2053 for GPB and 2047 for GKA) just to give themselves some future cushion.⁶⁸²

410. The JTG Study contained an alternative rail option that envisioned building a \$3 billion 20-inch replacement pipeline from the North Slope to Fairbanks, and then using rail to transport the oil from Fairbanks to tidewater. That approach would allow reserves to be booked down to 45,000 bbl/d, if justified by high oil prices.⁶⁸³

411. [CONFIDENTIAL – SEE SEALED ENVELOPE.] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

⁶⁸¹ MUN7-9094 at 8.

⁶⁸² MUN7-9094 at 8 (confidentiality waived on record at Tr. 11425).

⁶⁸³ Tr. 11411 (Haines); MUN7-3046 at 1.

[REDACTED]

412. BP Pipelines failed to provide the 2005 JTG Study in discovery for the 2006 ad valorem tax year proceedings.⁶⁸⁵ That study would have supported the Municipalities' position in that litigation that TAPS could operate down to 150,000 bbl/d or less, and may well have resulted in the Court finding a minimum capacity limit lower than the 200,000 bbl/d that this Court applied for that assessment year.⁶⁸⁶

413. In closing arguments to this Court, Owners' counsel asserted that the 2005 JTG Study was consistent with a 200,000 bbl/d limit south of Fairbanks because the study has a range of 200,000 to 135,000 bbl/d as the minimum limit, apparently referring to a North Pole off-take alternative scenario in the study.⁶⁸⁷ This position is not supported by the evidence; the JTG Study unambiguously states that "the low-flow limit of the existing 48" TAPS pipeline was determined to be a PS [Pump Station] 1 rate of 135 MB/Day [135,000 bbl/d]."⁶⁸⁸ And whatever the Owners' position as to how the 2005 JTG Study should be interpreted, the Owners' failure to bring that study forward resulted in the other parties, SARB, and this Court not being able to consider it until its production in the proceedings for the 2007 to 2009 tax years.

414. In 2010, BP Pipelines retained Phil Carpenter, a subject matter expert who was also used extensively by Alyeska in its Low Flow study, to determine whether TAPS could operate at levels below the 135,000 bbl/d threshold put forth in the 2005 JTG Study. At trial, Mr. Haines of BP Pipelines explained:

⁶⁸⁵ Tr. 13580-81 (Mahoney).

⁶⁸⁶ Amended Decision ¶ 122.

⁶⁸⁷ Tr. 13580-81 (Mahoney).

⁶⁸⁸ MUN7-3000 at 6, 7.

The JTG study . . . essentially had two different paths that you could live with . . . One path was you would throw investments at TAPS and eventually the south leg would die at a rate of 135. You would start a railroading apparatus at that point. . . the south leg always died first because of the extraction of oil at Fairbanks at the Fairbanks refinery . . . Except if you wanted to throw another \$3 billion at the problem and replace the north leg with a replacement 20-inch line . . . [so as to be able to transport down to 45,000 bbl/day] . . . And the economic hurdle of paying for that \$3 billion of replacement line investment created a very large stair-step in the economic profile, the granularity I was talking about.⁶⁸⁹

415. In a May 19, 2010 email, Mr. Haines provided Mr. Carpenter with a copy of the 2005 JTG Study and explained:

You probably want to start with the executive summary. As we discussed on the phone, our reserves reporting relied on a 'low oil price' scenario and a 'high oil price scenario.' These are identified in the report as Scenario 2 and Scenario 3. What we are looking for in your work effort is some sort of intermediate solution that could be used to extend the limit beyond 135 MBD [135,000 bbl/d] (Scenario 2), but would not have a \$3 billion hurdle that would allow us to get down to 45 MBD [45,000 bbl/d]. In other words, something for a "middle oil price" scenario.⁶⁹⁰

Thus, the 2010 Carpenter Study was undertaken by BP Pipelines to obtain a minimum throughput level below 135,000 bbl/d that did not have a "\$3 billion hurdle" associated with it that could be used for purposes of BP booking its proven reserves.⁶⁹¹

416. A June 11, 2010 email from Mr. Carpenter contained a list of over a dozen low throughput options he had analyzed.⁶⁹² On June 15, 2010, Mr. Haines responded back that:

I've had a chance to talk to our upstream reserves guys, and they advise that Option 2 (run cold and sweep with freeze suppressant) sounds like it might be pushing things too far, because it requires

⁶⁸⁹ Tr. 11410-11 (Haines).

⁶⁹⁰ MUN7-3046 at 1.

⁶⁹¹ Tr. 11411 (Haines); MUN7-3046 at 1.

⁶⁹² MUN7-3046 at 30.

achieving a level of confidence in the physics of the problem – a level of “proof” that our study will not be capable of fully defining. So, they agree we can drop it from the list⁶⁹³

Mr. Haines then discussed the various other options, concluding:

From a pragmatic viewpoint, it seems to me that item 1 (heaters) may be exactly what we’re looking for (in terms of finding a sure-fire way to bridge between the 135 MBD [135,000 bbl/d] endpoint and the large capital cost of replacing the north leg). I say this because if we can find a way to lower the endpoint from 135 MBD [135,000 bbl/d] to say something in the range of 100 MBD [100,000 bbl/d] or less, that kind of solution would probably act to close the gap our reserves guys are seeking.⁶⁹⁴

417. On June 28, 2010 Mr. Carpenter provided Mr. Haines with a “status update on the low flow work” in which he opined:

. . . I am beginning to think that it looks surprisingly good for ultra low flow below 100,000 [bbl/d]. . . Heating needs actually go down with decreasing flow after a certain point. In addition to heaters, the primary upgrades required are oil separation facilities in Valdez (which could rely to great extent on the existing tank system) plus a water treatment plant. Other upgrades would be safety upgrades required to deal with an extended pipeline shutdown. This option is particularly interesting because it also offers the possibility of shipping heavy viscous crude oil that may be coming down the line in the future. It does not currently appear that there are any downstream side effects.⁶⁹⁵

418. Consistent with that opinion, on July 20, 2010, Mr. Carpenter circulated a draft of the 2010 Carpenter Study: “The analysis concluded that point source heating of the oil is the best solution for operation of 100,000 [bbl/d].”⁶⁹⁶ Mr. Haines’ response to the draft stated:

⁶⁹³ MUN7-3046 at 29.

⁶⁹⁴ MUN7-3046 at 29. See also Tr. 11449-50 (Haines).

⁶⁹⁵ MUN7-3052 at 1.

⁶⁹⁶ MUN7-3056 at 6 (BP Pipeline interlineations omitted).

Thanks for the updated report. This is shaping up nicely, and is exactly the “fit for purpose” product we were looking for. . . . Probably the most significant edits we’ve made to your most recent draft involved turning on the railroad when the PS-1 rate hits 140 MBD [140,000 bbl/d] (and turning off the south leg), and running the north leg down to 70 MBD [70,000 bbl/d]. This means some of the south leg heaters will likely not be installed at rates below 140 MBD [140,000 bbl/d] (because of laminar flow issues).⁶⁹⁷

419. The final version of the 2010 Carpenter Study was dated August 16, 2010 and concluded that TAPS could effectively operate down to throughputs between 100,000 bbl/d and approximately 70,000 bbl/d.⁶⁹⁸ To operate at those throughputs, the study concluded that “[p]oint source heating of the oil (via heaters located at various intervals along the pipeline) is currently the best solution for enabling operations down to low throughput.”⁶⁹⁹

420. The 2010 Carpenter Study did not foreclose lower throughput levels below its conclusions, acknowledging that other technologies apart from point source heating “may eventually offer better solutions with fewer unknowns, lower throughput limits and lower shutdown risk, but these options are less developed and well understood at this time.”⁷⁰⁰ The Study stated that “50,000 [bbl/d] to 70,000 [bbl/d] is probably the limit for [the point source heating] approach due to wax deposition and pigging concerns. Further reduction in flow will require investigation of other options that maintain higher flow velocities, such as seawater commodity supplementation.”⁷⁰¹

421. On August 23, 2010, Larkspur issued the companion report to the Carpenter Study. The Larkspur Study details the location, estimated cost, and timing (based upon flow

⁶⁹⁷ MUN7-3051 at 1.

⁶⁹⁸ Tr. 10404-07 (Haines); MUN7-3020 at 6-8.

⁶⁹⁹ MUN7-3020 at 6. *See also id.* at 8 (laminar flow at “about 50,000 BPD”).

⁷⁰⁰ MUN7-3020 at 7.

⁷⁰¹ MUN7-3020 at 8.

rates) of the heaters necessary to operate all of TAPS down to 100,000 bbl/d.⁷⁰² Together with the Carpenter Study, the Larkspur Study demonstrates that the TAPS Owners are already considering the expenditure of significant resources to transport daily throughputs on TAPS far below the 300,000 to 350,000 bbl/d minimum throughput limit that the Owners are advancing in this case.

422. In the fall of 2010, BPPA used the lower minimum throughput determinations from the Carpenter Study in its transportation tariff calculations. Those calculations, in turn, were provided to BP Production forecasting personnel who then used that information to book BP's proven reserves in 2010.⁷⁰³ That BP relied upon the Carpenter Study's 100,000 to 70,000 bbl/d low flow estimate to book its reserves is compelling evidence that these figures may be reasonably relied upon by this Court to determine the assessed value of TAPS.

423. At trial, the Owners maintained that TAPS' minimum throughput limit is much higher. They referred to the extensive work done on the 2011 Alyeska Low Flow Impact Study ("LoFIS"), as testified to by Alyeska employee Pat McDevitt, in support of their position that TAPS has an operational lower capacity limit of 300,000 to 350,000 bbl/d.⁷⁰⁴ Mr. Carpenter, who prepared the BP Pipelines 2010 study for reserves purposes, was also a

⁷⁰² MUN7-3044; MUN7-3045. Thus, although BP Pipelines edited the final version of the 2010 Carpenter Study to reflect BP Pipelines' preference to "turn on" the North Pole Refinery, and thus assumes a limit of 140,000 bbl/d on the South leg, Larkspur's work is consistent with Mr. Carpenter's original analysis that did not distinguish between the low flow limits on the North and South legs.

⁷⁰³ Tr. 11415-17 (Haines).

⁷⁰⁴ Tr. 10751 (McDevitt).

core member of the Alyeska LoFIS team, with subject matter expertise in water transport, hydraulic size formation, and heat transfer.⁷⁰⁵

424. The LoFIS was an \$11 million study by Alyeska that reviewed many potential low-flow issues – including water dropout and corrosion, ice formation within the crude, wax deposition, and potential pipe displacement due to ice lenses in the soil. The public version of the Low Flow Study expressly concluded that “[f]low volumes of less than about 350,000 BPD subject TAPS operations and pipeline integrity to greater degrees of uncertainty that require investigation and study beyond that accomplished through the LoFIS. *Measures to mitigate these issues utilizing the existing 48-inch pipe at throughputs below 350,000 BPD have not been determined at the date of this report.*”⁷⁰⁶ Similarly, Mr. Haines testified that Mr. Carpenter and Larkspur “concluded that [TAPS] could run down to lower levels than what I understood the Alyeska team was currently examining,” and that 300,000 bbl/d was the “lower range of [the LoFIS] effort.”⁷⁰⁷ This was also consistent with Mr. McDevitt’s testimony that the purpose of LoFIS was “to look at TAPS’ low flow down to 300,000 bbl/d”.⁷⁰⁸ This Court finds, based on the evidence presented at trial, that the LoFIS was primarily limited to studying operating challenges with throughputs down to 300,000 bbl/d and not below that level.⁷⁰⁹ Its focus was not to determine TAPS’ minimum throughput capacity.

⁷⁰⁵ Tr. 10960-61 (McDevitt); MUN7-3020 at 12-14.

⁷⁰⁶ Executive Summary of Low Flow Impact Study Final Report at 3 (public version, June 15, 2011), available at http://www.alyeska-pipe.com/Inthenews/LowFlow/LoFIS_Summary_Report_P6%2027_ExSum.pdf (emphasis added). See Evidence Rule 201.

⁷⁰⁷ Tr. 11403-04 (Haines).

⁷⁰⁸ Tr. 10979 (McDevitt). See also MUN7-3056 at 6-7 (confidential statement by Mr. Carpenter).

⁷⁰⁹ Tr. 10975-82 (McDevitt); Tr. 11404 (Haines).

425. While the LoFIS discussed many potential problems at lower throughputs and recommended further study for solutions, it did not establish by a preponderance of the evidence that TAPS cannot operate below 300,000 bbl/d. Although Pat McDevitt, the project manager for LoFIS, testified that it is “not possible” for TAPS to operate below 300,000 bbl/d, this Court found that testimony, when considered with all of the other evidence at trial presented on this topic, to be completely unpersuasive.⁷¹⁰ Mr. McDevitt declined to present himself as a subject matter expert in any of his areas of concern.⁷¹¹ Furthermore, no other expert made an absolute statement as to TAPS’ minimum capacity. For example, Alyeska engineer Joe Riordan testified that he did not know for a fact that TAPS could not operate at 100,000 bbl/d.⁷¹² This Court concurs with the Department’s assertion that in the case of Mr. McDevitt, “it is difficult to separate advocacy from engineering analysis that has been fully vetted and tested.”⁷¹³

426. Mr. McDevitt did not clearly articulate a specific reason why TAPS would cease to operate at any particular capacity level, but instead articulated a number of operational concerns that have not yet been fully studied.⁷¹⁴ For example, when asked for the primary reason why TAPS would be unable to operate below 300,000 bbl/d, he indicated low velocity pigging could constrain TAPS’ operation at low flows.

⁷¹⁰ Tr. 11025-27, 11093 (McDevitt).

⁷¹¹ Tr. 10963-68 (McDevitt).

⁷¹² Tr. 5129 (Riordan).

⁷¹³ Department’s Proposed Findings of Fact and Conclusions of Law ¶ 202.

⁷¹⁴ Tr. 11027-28 (McDevitt).

427. Pigging becomes more critical as the oil slows and the temperature of the oil decreases, because wax precipitation and deposition increase.⁷¹⁵ This wax deposition is primarily addressed through increased pigging of the pipeline. The August 2010 Carpenter Study used a 7-day pigging schedule with approximately 20 pigs in the pipeline for its 70,000 bbl/d scenario.⁷¹⁶ Mr. Carpenter nonetheless recognized that “pipeline scraper and inspection pig viability at low flow is a considerable concern at very low flow,”⁷¹⁷ and recommended that “Alyeska and/or its Owners implement a long-term research and development program to implement mission critical pigs.”⁷¹⁸ But over one year after that report was issued, Mr. McDevitt testified at trial that he was unaware of any conceptual engineering work underway at Alyeska to address these pigging issues, and was unaware of any pig manufacturer that had been contacted for the purpose of designing, developing or testing low velocity pigs for TAPS.⁷¹⁹

428. As noted above, BP pipelines provided extensive comments on a July 20, 2010 draft of Mr. Carpenter’s Study. One exchange related to Alyeska’s low flow work. BP Pipelines commented that:

Recognizing that your work here goes beyond (and has a somewhat different focus than) the [Alyeska] Low Flow team’s work, we want to ensure that everything said in this report would not contradict the work done by the Low Flow team or be in conflict with what their report might say when it is issued in 3Q. In particular, we’ve been picking up some recent rumors that the Low Flow team’s optimism about achieving very low throughput rates has started to wane a little in

⁷¹⁵ Tr. 10918 (McDevitt).

⁷¹⁶ MUN7-3020 at 40.

⁷¹⁷ MUN7-3020 at 40.

⁷¹⁸ MUN7-3020 at 40.

⁷¹⁹ Tr. 11075-77, 11085 (McDevitt). See also Tr. 9224 (Malvick).

recent months, but we don't know if there's any merit to this. So, we were hoping you could bring us up to speed on Friday.⁷²⁰

Mr. Carpenter responded: "I think that your concern is valid. The primary concerns are (1) the ability to pig the line at very low flow and (2) the impact of shutdowns and slowdowns on oil temperature and wax accumulation."⁷²¹ Another drafting note by BP Pipelines stated:

Phil, I'm wondering whether you could develop a list of the additional heaters required to get down to say 70-80,000 [bbl/d]. This way we could get a sense of how impractical the number of heaters is getting to be as the rate goes below 100 MBD [100,000 bbl/d]. If it looks like maybe 3 or 4 more heating stations will do the job, then perhaps it is still within the range of being economic. I know this says nothing about the ability to pig at such low rates, or whether wax sedimentation is insurmountable. I guess what I'm trying to say is – is there any room to move this number lower without pushing the boundaries of good engineering judgment? Or, is 100 [100,000 bbl/d] about the limit of how low you think TAPS can go with point heating.⁷²²

Mr. Carpenter's response was:

My biggest concern with ultra flow and heating is the ability to pig and the potential for wax sedimentation/sludge accumulation in laminar flow. I've refined my numbers a bit and right now the laminar flow limit in the north end is about 70,000 [bbl/d], which probably eliminates that sludge issue but does not solve the pig issue.⁷²³

429. Thus, while Mr. Carpenter expressed concerns with pigging, he was sufficiently confident the "pig issue" could be solved that he concluded TAPS could operate at the "70,000 [bbl/d] benchmark" discussed in his report.⁷²⁴

430. This Court finds the JTG and Carpenter studies, which were conducted by TAPS' largest Owner for the specific purpose of evaluating the ability of TAPS to operate at

⁷²⁰ MUN7-3056 at 6-7.

⁷²¹ MUN7-3056 at 7.

⁷²² MUN7-3056 at 8.

⁷²³ MUN7-3056 at 8.

⁷²⁴ MUN7-3020 at 10.

throughputs well below 300,000 bbl/d and relied upon by BP for booking its proven reserves, to be far more persuasive than the LoFIS study in determining TAPS' minimum throughput capacity.

431. At trial, the Municipalities' expert Dr. Jerry Modisette persuasively opined why he had determined that TAPS could operate at 100,000 bbl/d. Indeed, Dr. Modisette asserted TAPS could operate at far lower throughputs than that, particularly if the oil were recirculated through the pumps so as to raise its temperature – a project Alyeska is planning to try this winter.⁷²⁵

432. With regard to the low-flow operational issues identified in the Alyeska study, including water dropout and corrosion, ice formation within the crude oil, ice lenses or frost heaves in the soil, and wax precipitation and deposition, the weight of the evidence at trial persuaded this Court that it is more likely than not that there will be engineering solutions to mitigate these problems on TAPS at throughputs down to 100,000 bbl/d or less.⁷²⁶

433. Heating the pipeline will likely be a major component of any low-flow mitigation approach. Mr. Malvick stated that Alyeska is currently studying and planning for heating TAPS via installation of point source heaters, enhanced recycling of crude at pump stations, bringing Pump Station 7 back into service as a heating station, enhanced pipeline insulation, and waste heat recovery at Pump Stations 3 and 4.⁷²⁷ As of the time of trial in late 2011, Alyeska and the Owners had not yet purchased any heaters for TAPS.⁷²⁸

⁷²⁵ Tr. 9014-15 (Modisette).

⁷²⁶ See, e.g., Tr. 8961-62 (Hisey).

⁷²⁷ Tr. 1969, 1974, 1978-80 (Malvick).

⁷²⁸ Tr. 1828-29 (Riordan).

434. The August 2010 Larkspur Study estimates approximately \$2 billion in undiscounted costs for heating TAPS so as to be able to transport 100,000 bbl/d.⁷²⁹ This is based on the 2010 Carpenter Study's use of substantial redundancy resulting in 70% excess heating capacity.⁷³⁰ Thus, the actual cost could well be considerably lower. However, even Larkspur's estimated expense is self-evidently economic in light of the value of TAPS' proven reserves. The Court was persuaded by Mr. Hisey's testimony that even if the heating and other mitigation measures cost upwards of hundreds of millions of dollars in the coming decades, it would still be economical to make such investments to keep TAPS operating at and below 100,000 bbl/d "to move North Slope crude oil and keep that transportation base available for future fields, future production."⁷³¹

435. As noted above, Mr. Haines used the 2010 Carpenter Study and the Larkspur Study as the basis for TAPS' minimum throughput capacity in developing the per barrel transportation tariffs that BP relied upon to book its proven reserves.⁷³² At the trial de novo, Owners' counsel asked Mr. Haines what weight he would give the 2010 Carpenter Study today if he were to determine TAPS' minimum throughput capacity, after Alyeska's \$11 million low flow study had been completed.⁷³³ Mr. Haines testified:

It seems to me that if I had to sit back and do tariffs again, I would be – have to give a lot of weight to – to the one that seems to me to be – have more depth behind it and engineering facts, and that would have to be – I would have to seriously weight what I saw with – with the Alyeska result.⁷³⁴

⁷²⁹ MUN7-3045 at 2.

⁷³⁰ MUN7-3020 at 29-31.

⁷³¹ Tr. 9000 (Hisey).

⁷³² Tr. 11474-75 (Haines).

⁷³³ Tr. 11484 (Haines).

⁷³⁴ Tr. 11485-86 (Haines).

Thus, Mr. Haines did not say that he believed the 2010 Carpenter Study was inaccurate, presented incorrect information, or was improper to rely upon to book reserves in the past or future, but only that he would “seriously weigh” the Alyeska opinions presented at trial by Mr. McDevitt.

436. The Owners did not seek to have Mr. Carpenter testify at trial, notwithstanding the Court’s specific indication during trial that a motion could be brought to do so.⁷³⁵

437. This Court finds the conclusions reached in the 2005 JTG study, together with the opinions reached in the 2010 Carpenter Study and Larkspur Study, as well as the opinions of Dr. Modisette and Mr. Hisey, to be more credible and persuasive than Mr. McDevitt’s opinion on TAPS’ minimum throughput capacity.

438. For the foregoing reasons, and after careful consideration of all of the evidence presented at trial, this Court finds it more likely than not that TAPS can effectively transport throughputs at least down to a minimum flow rate of 100,000 bbl/d.

b. Proven Reserves

i. The Definition of Proven Reserves

439. The applicable statute requires consideration of the “estimated life of the proven reserves of gas and unrefined oil then technically, economically and legal deliverable into the transportation facility.”⁷³⁶

440. Various definitions of the term “proven reserves” have been advanced by the parties and considered by this Court during the course of these proceedings.⁷³⁷ For the

⁷³⁵ Tr. 11505 (Court); Alaska Civil Pattern Jury Instruction 02.23.

⁷³⁶ AS 43.56.060(e)(2).

2006 tax year, this Court declined to further define proven reserves beyond the statutory language, and held that the statute required an estimation of the total proven reserves, and then a determination made as to which of those proven reserves were deliverable to the pipeline as of the valuation date.⁷³⁸

441. In an order issued on August 16, 2011, this Court again declined to create a more refined definition of “proven reserves” than is set forth in the statute, and again held that the statutory phrase “then technically, economically and legally deliverable” provides a further restriction on the amount of proven reserves that can be considered in determining the full and true value of TAPS.⁷³⁹

442. In their proposed findings, the Owners urge this Court to adopt a requirement that reserves be proven to a level of “reasonable certainty” before they can be considered as “proven reserves” for ad valorem tax purposes. They cite to the Securities and Exchange Commission (“SEC”) definition, which effective January 1, 2010, provides as follows:

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.⁷⁴⁰

⁷³⁷ See Owners’ Mot. for Rule of Law on Meaning of Proven Reserves within AS 43.56 (May 27, 2011); Municipalities’ Opp’n to TAPS Owners’ Mot. for Rule of Law on Meaning of Proven Reserves within AS 43.56 (June 29, 2011); 2007 R. 3541- 3561; Tr. 9705-06 (Van Dyke).

⁷³⁸ See Order re TAPS Owners’ Motions of May 27, 2011 at 2, n. 3 (Aug. 16, 2011).

⁷³⁹ See Order re TAPS Owners’ Motions of May 27, 2011 at 2 (Aug. 16, 2011).

⁷⁴⁰ 17 CFR § 210.4-10 (effective 2010); Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 698.

443. The Owners note that publicly traded companies listed on the U.S. stock exchange must report their proven reserves using this SEC definition.⁷⁴¹ They assert that “[t]he SEC rules provide for a consistent and reliable industry understanding of the term and the meaning of ‘proven reserves’ for booking those reserves for financial reporting and for public disclosures.”⁷⁴² They argue that this standard should be adopted by this Court for the ad valorem assessment of TAPS, as it reflects “current technical understanding of the term as used in the United States.”⁷⁴³

444. In effect, the Owners’ urge the adoption of a heightened burden of proof so as to require that the reserves be proven to a level of “reasonable certainty” before they can be considered in the ad valorem assessment of TAPS.

445. A 1965 Society of Petroleum Engineers’ (“SPE”) definition of “proved reserves” in effect when AS 43.56 was enacted read as follows:

Proved Reserves—The quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. They represent strictly technical judgments, and are not knowingly influenced by attitudes of conservatism or optimism.⁷⁴⁴

446. There is a similarity between AS 43.56.060(e)(2) and the 1965 SPE definition for “proved reserves,” and it is possible that Legislators considered the SPE definition when drafting the ad valorem tax statutes.⁷⁴⁵ And yet, as this Court has previously noted, the Legislature did not articulate any particular confidence level in the statutory definition of

⁷⁴¹ Tr. 9867-68 (Hoolahan).

⁷⁴² Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 697.

⁷⁴³ Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 702.

⁷⁴⁴ 2007 R. 3546.

⁷⁴⁵ See 2007 R. 3534.

"proven reserves" for ad valorem tax purposes, such as proven by a "preponderance of the evidence" or "reasonable certainty."⁷⁴⁶

447. "Preponderance of the evidence is the general burden of persuasion in civil cases."⁷⁴⁷ On occasion, such as with civil statutes that are quasi criminal in nature, the Alaska Supreme Court has established a higher burden. But in this tax case, and in the absence of a clear legislative articulation of a heightened standard, the preponderance of the evidence standard should control.

448. Moreover, no persuasive justification has been demonstrated here for creating a heightened burden of proof for ad valorem tax purposes. Government reporting agencies such as the SEC require a heightened burden of proof from oil producers that the reserves they are asserting as proven have actually been ascertained to a degree of reasonable certainty. That heightened burden, however, is imposed upon the entities that have full access to the data they are required to submit, and is intended for investors to be able to rely upon in formulating investment decisions.

449. The history of this case demonstrates that it has been exceedingly difficult for the Municipalities to obtain any proven reserves information from the Owners and their affiliates. Only a limited amount of reserves information has been made available to the Municipalities – and certainly not due to a lack of effort on their part both before the trial court and on repeated petitions for review to the Alaska Supreme Court. To require a

⁷⁴⁶ See Amended Decision ¶ 396.

⁷⁴⁷ *Fernandes v. Portwine*, 56 P.3d 1, 6 (Alaska 2002) (citing *Addington v. Texas*, 441 U.S. 418, 423 (1979) (the burden in typical civil cases is preponderance of the evidence); *Spensard Action Comm.*, 902 P.2d at 775 (the general civil standard is preponderance of the evidence); *Cavanah v. Martin*, 590 P.2d 41, 42 (Alaska 1979) ("The standard of proof in civil cases is proof by a preponderance of the evidence."). See also AS 43.05.435(1) (in tax appeals heard by administrative law judge, the judge shall "resolve a question of fact by a preponderance of the evidence, or if a different standard of proof has been set by law for a particular question, by that standard of proof.").

heightened burden of proof of the proven reserves from the Municipalities when they have been unable to obtain all of the proven reserves information they have so vigorously sought from the Owners and their affiliates could result in an ad valorem valuation that is not a “full and true value” of the pipeline. This Court finds it more likely that a construction of the statute “that rigidly adopted the petroleum industry’s concept of proved reserves would lead to impermissible inequities in tax assessment.”⁷⁴⁸

450. The Owners also cite to AS 01.10.040(a) in urging the adoption of the SEC definition. This statute provides that “[t]echnical words and phrases and those which have acquired a peculiar and appropriate meaning, whether by legislative definition or otherwise, shall be construed according to the peculiar and appropriate meaning.”⁷⁴⁹ But the record demonstrates that in addition to the reserves information that an oil producer provides to the SEC using the government’s reporting standards, an oil producer also maintains its own proprietary reserves information, which can be based on a variety of different economic and other assumptions from the SEC requirements.⁷⁵⁰ The record establishes that the term “proven reserves” has not acquired a peculiar or appropriate meaning. Accordingly, this Court finds that for ad valorem tax purposes under AS 43.56, reserves must be proven by a preponderance of the evidence, and not by any heightened standard.

451. The word “then” preceding “technically, economically and legally deliverable into the transportation facility” in AS 43.56.060(e)(2) imposes a temporal restriction that

⁷⁴⁸ *Maples v. Kern County Assessment Appeals Bd.*, 103 Cal. App. 4th 172, 196 (Cal. Ct. App. 2002). See also Municipalities’ Proposed Findings of Fact and Conclusions of Law ¶¶ 677, 678.

⁷⁴⁹ Owners’ Proposed Findings of Fact and Conclusions of Law ¶ 691.

⁷⁵⁰ Tr. 9718-24 (Van Dyke).

requires that for proven reserves to be included in the valuation analysis of TAPS, they must be technically, economically, and legally deliverable as of the valuation dates each year.

452. This Court interprets the requirement that the oil be “technically” deliverable into the pipeline to mean that the technology exists as of the lien date for the oil to be deliverable to the pipeline. This Court again finds that the existence of pipeline and production facilities to a particular field as of the lien date is not a prerequisite for those reserves to be considered technically deliverable under the statute, so long as the technology exists for the oil to be deliverable to the pipeline as of the lien date.⁷⁵¹ This finding is consistent with many definitions of the term “proven reserves,” including those adopted by the SEC and the SPE, which distinguish between proved developed reserves and proved undeveloped reserves.⁷⁵² Reserves that do not have infrastructure in place are still considered proven, but are categorized as proved undeveloped.⁷⁵³

453. Further, as previously discussed in this decision, this Court adopts the Board’s interpretation of the statutory provision that reserves be “technically deliverable ... into the transportation facility” to permit a pipeline owner to prove by a preponderance of the evidence that a pipeline has a minimum throughput capacity.

454. This Court finds that the “legally deliverable” requirement is satisfied so long as the totality of the circumstances demonstrate that it is reasonable to assume that all necessary permits and licenses to allow for the extraction of proven reserves from a given

⁷⁵¹ See Amended Decision ¶ 401.

⁷⁵² Tr. 9872 (Hoolahan).

⁷⁵³ Tr. 10084 (Hoolahan).

pool will be granted or renewed, and there exist no legal prohibitions against delivering those reserves to TAPS as of the lien date.

455. In the case of the Point Thomson Unit (“PTU”), the Department of Natural Resources had terminated the unit as of November 2006, so reserves from the PTU should not be included in the proven reserves as of the January 1, 2007 lien date because of the legal prohibition on development. In December 2007, the Superior Court reversed the unit termination decision and remanded the matter back to the agency for further proceedings. Thus, the PTU should be included as legally deliverable proven reserves as of the January 1, 2008 lien date.⁷⁵⁴ But as of the January 1, 2009 lien date, the unit had again been terminated by the agency, and the appeal to the superior court was pending. Thus, the PTU should not be included in the proven reserves analysis as of that date. The PTU satellites have been included as proven reserves in all three of the lien years since no persuasive evidence was presented that they were included within the agency's unit termination decisions.

456. This Court was completely unpersuaded by the testimony of the Owners' witness Jack Hartz that the “legally deliverable” provision set forth in the statute includes only those quantities of oil that are contained in reservoirs for which the producers, as of the lien date, have every permit and license necessary to allow immediate extraction and delivery of crude oil to TAPS.⁷⁵⁵ Such an approach would result in an improper valuation of the pipeline.

⁷⁵⁴ See *ExxonMobil v. State*, Superior Ct. Case No. 3AN-06-13751 CI.

⁷⁵⁵ Tr. 10143-45 (Hartz).

457. Natural gas liquids (“NGLs”) produced at Prudhoe Bay that are contractually committed for shipment to Kuparuk would not be legally deliverable to TAPS.⁷⁵⁶ However, the Owners failed to present sufficient evidence as to the amount of such reserves.⁷⁵⁷

458. To be economically deliverable, the anticipated price for a barrel of oil to be delivered to market must exceed the cost of its production, including the cost of transportation. Each party performed an economic analysis of the proven reserves for this proceeding.

459. Thus, so long as oil in each of the three categories of ANS production established by the Department of Revenue – producing, under development, and under evaluation – was economically, technically, and legally deliverable into TAPS as of the lien date, as proven by a preponderance of the evidence, that oil should be included when estimating the economic life of TAPS for ad valorem tax purposes.

460. This is consistent with the testimony of experts in this case and before SARB that “technically, economically, and legally” are common elements of proved reserves definitions,⁷⁵⁸ and that their determination of “proven reserves” would not have been materially different had the “technically, economically, and legally” language been absent.⁷⁵⁹ That is because each of these three requirements are explicitly or implicitly contained in most, if not all, definitions of proved reserves.

⁷⁵⁶ Tr. 10038 (Hoolahan).

⁷⁵⁷ There are references to the exclusion of these NGLs in some of Mr. Hoolahan's charts, but the amounts are unspecified. See, e.g., T0-07-0092 at 39, 46, 53.

⁷⁵⁸ Tr. 10579-81 (Greeley); Tr. 10037-38 (Hoolahan); Tr. 10527-29 (Molli); Tr. 9831-32, 9837-39 (Van Dyke); Tr. 9412 (Platt); 2007 SARB Tr. 0765, 0772 (Garb).

⁷⁵⁹ Tr. 9870-71 (Hoolahan); Tr. 9708-09 (Van Dyke).

461. The economically recoverable proven reserves estimates, in billions of barrels of oil, presented by each of the parties at trial were as follows:

<u>Party</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>
Owners Hoolahan (Initial Report) ⁷⁶⁰	1.884	1.949	1.307
Owners Hoolahan (Corrected) ⁷⁶¹	4.163	4.119	3.092
Department of Revenue Molli / Greeley ⁷⁶²	5.436	5.169	4.929
Municipalities Platt / Van Dyke ⁷⁶³	8.198	7.759	7.362

In addition to the foregoing, confidential proven reserves estimates from BP Exploration (Alaska) Inc. were provided through discovery and admitted as evidence. The Owners and the Department did not present any witness that directly addressed BPXA's confidential estimates.

\\

\\

\\

\\

\\

⁷⁶⁰ T0-07-0146.147. These are Mr. Hoolahan's 1P estimates – which he defines as "proved developed reserves." T0-07-0007.08.

⁷⁶¹ T0-07-92 (corrected) at 22. These are Mr. Hoolahan's 2P estimates – which he defines as "proved plus probable developed reserves" with some augmented data from Mr. Molli. T0-07-0007.08. The 1P estimates do not appear in his corrected report.

⁷⁶² SOA7-6 at 11. Note, however, this assumes a 150,000 million bbl/d throughput limitation. Actual proved reserves would be higher.

⁷⁶³ MUN7-4306 at 6; MUN7-4313 at 6; MUN7-4309 at 7.

462. [CONFIDENTIAL – SEE SEALED ENVELOPE.] [REDACTED]

[REDACTED]

[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

463. The parties also presented some evidence of reserves information that has been made publicly available through various government agencies. This included a Department of Energy Report dated August 2007 which estimated that the remaining

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

economically recoverable oil from existing fields on the ANS was between 6 and 7 billion barrels as of December 31, 2004.⁷⁷⁰

464. The Owners' appraiser Michael Remsha did not rely upon the Owner's reserves expert Shaun Hoolahan's proven reserves estimates, but instead used the Department of Revenue's throughput projections to which he applied a discount. His discounted remaining throughput projections as of the lien dates ranged from 2.0 billion barrels to 6.2 billion barrels.⁷⁷¹

ii. The Municipalities' Production Forecasts and Reserves Estimates Generally Provide a Reliable Basis for Determining TAPS' Estimated Proven Reserves

465. Dudley Platt is one of the preeminent production forecasters in the state, although he is not a petroleum engineer. He began making oil production forecasts for the State of Alaska in 1989.⁷⁷² Mr. Platt prepared a production forecast for the Department every year through 2009.⁷⁷³ This Court relied on Mr. Platt's production forecast to determine TAPS' end-of-life in the 2006 tax year trial.⁷⁷⁴

466. Mr. Platt used a comprehensive "lease sale to abandonment" approach to his forecasting in which he considered lease acquisition, unitization and field development, and how multiple pools produce using evolving technologies and numerous reservoir drive mechanisms to common surface facilities.⁷⁷⁵

⁷⁷⁰ MUN7-0001-4232.

⁷⁷¹ TO-07-0004.0260.

⁷⁷² Tr. 9338 (Platt).

⁷⁷³ MUN7-0238 at 21.

⁷⁷⁴ Amended Decision ¶ 398.

⁷⁷⁵ Tr. 9343-48 (Platt).

467. Mr. Platt also testified that he relies upon reports filed by the producers with the Alaska Oil & Gas Conservation Commission in determining what proved reserves are technically recoverable.⁷⁷⁶ Those reports detail not only industry estimates regarding the quantities of oil in place, but also industry estimates regarding the amounts of oil recoverable using established methods of extraction.⁷⁷⁷ These estimates are based on standard industry techniques, including seismic mapping, computer simulation, and exploratory drilling.⁷⁷⁸ The evidence at trial demonstrated that the estimates of the economic life of Prudhoe Bay reported by the BP Prudhoe Bay Royalty Trust ("Royalty Trust") to the SEC correlate well with Mr. Platt's economic models when he used the SEC fixed price for comparison purposes.⁷⁷⁹

468. Decline curve analysis is one component in the determination of the economic life of ANS proven reserves.⁷⁸⁰ Mr. Platt's forecast incorporated a decline curve analysis at the pool level, as opposed to a well-by-well analysis used by both the Owners' and Department's witnesses.⁷⁸¹ Mr. Platt persuasively testified that, based on his experience working in the oil industry, long-range production forecasters do not use decline curves on a well-by-well basis.⁷⁸² Mr. Van Dyke explained that well-by-well analysis can work well for a small lease in Kansas with four wells, but not for a field with 1,000 wells that are regularly being turned on and off: "it's not the best approach to use a well-by-well method as

⁷⁷⁶ Tr. 9351-52 (Platt).

⁷⁷⁷ Tr. 9351-52 (Platt).

⁷⁷⁸ Tr. 9351-53 (Platt); Tr. 9384-85 (Platt).

⁷⁷⁹ Tr. 9388-89 (Platt).

⁷⁸⁰ Tr. 10498-99 (Molli).

⁷⁸¹ Tr. 9356 (Platt).

⁷⁸² Tr. 9431-32 (Platt).

compared to the pool – a pool level method to forecast production.”⁷⁸³ Decline curve analysis at the well level requires subjective analysis of highly variable historic data to estimate future production rates for each well.⁷⁸⁴

469. [CONFIDENTIAL – SEE SEALED ENVELOPE.] [REDACTED]

[REDACTED]

[REDACTED]

470. The legislative history of AS 43.56 supports the use of a pool forecasting methodology. At a 1973 Finance Committee hearing on the bill, “Mr. Heier asked if the Division of Oil & Gas could furnish the state assessor’s office projections well by well as to future productions. Mr. Burrell [of the Division] said it could be done more accurately on a field basis, as one well could dry up immediately.”⁷⁸⁶

471. Based on the evidence presented at trial, this Court finds that for determining the economic life of TAPS, a pool-based analysis is generally preferable to a well-based analysis.

472. One of the components of a decline curve analysis is the “b-factor.” Mr. Platt, on a pool basis, and Mr. Molli, on a well-by-well basis, both used b-factors to depict the rate at which oil production declines over the life of the projection. Mr. Platt was criticized for his use of b-factors greater than the value of 1.0 for several pools because some theorists maintain that b-factors must fall between the value of zero and one, and may never be greater than the value of one.

⁷⁸³ Tr. 9764 (Van Dyke).

⁷⁸⁴ Tr. 9425-28 (Platt); Tr. 9429-32 (Platt); Tr. 9356 (Platt).

⁷⁸⁶ *Minutes* at 50, H. Finance Comm., 8th Leg., 1st Spec. Sess. (Oct. 22, 1973) [2007 R. 9736].

473. A b-factor greater than 1.0 projects infinite production over an infinite period of time.⁷⁸⁷ Yet Mr. Molli acknowledged at trial that when a b-factor of .5 is used it takes approximately two billion years for production to converge to close to zero.⁷⁸⁸ Thus, whether a b-factor assumption models a pool or well that produces for two billion years or forever is not significant, because forecasters use economic tests to terminate production at some point several decades in the future – long before two billion years.⁷⁸⁹

474. [CONFIDENTIAL – SEE SEALED ENVELOPE.] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

475. Mr. Platt used b-factors for Prudhoe Bay of 1.0 for 2009, and 1.054 for both 2008 and 2007.⁷⁹²

476. Witnesses for both the Department and the Owners asserted that Mr. Platt had overestimated short-term production. But Mr. Platt persuasively testified that the major reason for that over-estimation was due to short-term interruptions in production and the

⁷⁸⁷ Tr. 10503-04 (Molli).

⁷⁸⁸ Tr. 10546 (Molli).

⁷⁸⁹ Tr. 10546-47, 10559-61 (Molli).

⁷⁹² SOA7-12 at 5.

delay of ANS fields and projects coming online, such that the oil he forecasted will eventually be recovered.⁷⁹³

477. Mr. Platt's economic testing assumed that a pool will stop producing oil during the first year that the costs for extracting the oil from that pool exceed the revenue generated from the sale of that oil.⁷⁹⁴ He also assumed that operating costs would remain flat over the life of a given field. In reality, real operating costs typically decrease over the economic life of the field.⁷⁹⁵

478. Economic testing of reserves also requires forecasting the future price of oil. There are several methods: (1) "point in time" forecasting, which uses the price of oil on a specific date as the price for all future oil sales;⁷⁹⁶ (2) basing the price on historical data over an established time period;⁷⁹⁷ and (3) setting prices based upon a forward-looking forecast.⁷⁹⁸

479. Until 2010, the SEC required producers to use "point-in-time" forecasting using the price of oil on the last trading day of the relevant calendar year as the price for all future sales.⁷⁹⁹ For investors, such an approach permits a meaningful comparison among different companies. But this Court finds that the historical "point in time" method of price forecasting for ad valorem tax purposes results in substantial year-to-year volatility of economic end-of-

⁷⁹³ Tr. 9447-48 (Platt); Tr. 9989-90 (Hoolahan).

⁷⁹⁴ Tr. 9371-72 (Platt).

⁷⁹⁵ Tr. 9374-75 (Platt); Tr. 9407-09 (Platt) (confidential); Tr. 9561-62 (Platt) (confidential); MUN7-4406 at 3, 5; Tr. 10066-67 (Hoolahan).

⁷⁹⁶ Tr. 10029 (Hoolahan).

⁷⁹⁷ Tr. 10620-21 (Greeley).

⁷⁹⁸ Tr. 9376-79 (Platt); Tr. 9558-60 (Platt).

⁷⁹⁹ Tr. 9420-21 (Platt).

life estimates. The SEC ameliorated the volatility of this approach to some degree when it amended its regulations in 2010 to use the monthly average price of oil during the prior year instead of December 31.⁸⁰⁰ The Court finds it more reasonable for the purposes of economic testing under AS 43.56.060(e)(2) to use a historical average of prices or credible forward-looking oil price forecasts.

480. Mr. Platt relied upon the U.S. Department of Energy's Energy Information Administration ("EIA") price forecast, which forecasted real market price growth for each of the three assessment years at approximately 1% per annum.⁸⁰¹ Based on the evidence presented at trial, this Court finds that reliance on that forecast was reasonable. Oil prices during the three assessment years were volatile, such that the forward-looking projections made by the EIA during that period varied considerably. Yet the highest oil price forecasted by the EIA for calendar year 2011 during the assessment years was \$74.08 per barrel, while the actual price of oil on October 18, 2011 was \$113 per barrel.⁸⁰² Mr. Platt also explained that due to the highly progressive nature of Alaska's production tax, oilfield economics at high real oil prices are not materially affected by price variations.⁸⁰³ Overall, this Court found Mr. Platt's production forecast and economic testing to be persuasive.

iii. The Forecasts and Reserves Estimates Offered by the Owners' Witnesses were not Persuasive

481. The Owners presented economist Roger Marks to testify with respect to proven reserves. Mr. Marks' testimony regarding the reserves estimates he derived from

⁸⁰⁰ Tr. 9386-87 (Platt); Tr. 9949-50 (Hoolahan).

⁸⁰¹ Tr. 9376-79 (Platt).

⁸⁰² Tr. 9565-67 (Platt). See also Tr. 10039-40 (Hoolahan).

⁸⁰³ Tr. 9565-66 (Platt).

the oil producers' SEC filings was not persuasive.⁸⁰⁴ His testimony was at odds with Mr. Van Dyke's testimony regarding the SEC filings by the BP Prudhoe Bay Royalty Trust. This Court found Mr. Van Dyke's testimony to be considerably more persuasive, in large part because Mr. Van Dyke correlated his findings with the BPXA confidential reserves information and also referred the Court specifically to the precise language and numbers in the SEC filings that informed his analysis.⁸⁰⁵

482. Petroleum engineer Shaun Hoolahan presented production forecasts and reserves estimates on behalf of the Owners. For a number of reasons, this Court found his conclusions to be unpersuasive.

483. Unlike all the other production forecasts presented in this case, Mr. Hoolahan's reports do not specify the expected amount of oil production each year for each of the fields over the projected life of that field. Instead, that information is set out in aggregated charts that are imprecise.

484. Mr. Hoolahan testified whether his estimated production had been higher or lower than the actual production for the past few years. But the testimony did not include the amount of production he had estimated, but simply indicated whether his prediction had been too high or too low.⁸⁰⁶ Without knowing the amounts he had predicted to compare to actual production, the analysis was unpersuasive.

⁸⁰⁴ Tr. 10391-93 (Marks).

⁸⁰⁵ Tr. 9727-33 (Van Dyke). The testimony there refers to MUN7-4072 (excerpts of the BP Royalty Trust SEC filings), which was admitted as MUN7-0001 at tab 58, p. 2006. At closing arguments, Owners' counsel distributed and referred to various pages from what appeared to be SEC 10-k 2008 filings from ConocoPhillips.

⁸⁰⁶ See generally T0-07-0007 at 103-119.

485. Mr. Hoolahan testified that he used only publicly available information to perform his initial analysis.⁸⁰⁷ The reason for this is not clear, given that the record in this case demonstrates that at least one of the TAPS Owners, BPPA, has had access to ANS reserves information through its affiliate. Mr. Hoolahan acknowledged that he had insufficient information for a proper assessment of proved undeveloped reserves.⁸⁰⁸ He later augmented his report with information he received from the Department's expert Mr. Molli to increase his proven undeveloped estimates.⁸⁰⁹

486. Mr. Hoolahan assumed five years of new wells from the date of each assessment. After that, he assumed that no new wells would be drilled on the ANS.⁸¹⁰ This restrictive assumption is not reasonable, based upon this Court's review of all the evidence.

487. Mr. Hoolahan used what he termed a "cut-cum" methodology on a well-by-well basis to assess ANS reserves, which is shorthand for water cut vs. cumulative oil.⁸¹¹ Although this Court has been presented with considerable amounts of complicated technological information during this case, and has strived and in large part succeeded in understanding it, this Court found Mr. Hoolahan's lengthy explanation of the methodology that he used to determine ANS reserves to be virtually incomprehensible. Additional efforts by this Court to try to understand Mr. Hoolahan's methodology by reviewing his reports were also unsuccessful, particularly because no actual production estimates by year or other data was provided except in conclusory form and imprecise charts.

⁸⁰⁷ Tr. 10074 (Hoolahan).

⁸⁰⁸ Tr. 10072 (Hoolahan).

⁸⁰⁹ Tr. 10074 (Hoolahan).

⁸¹⁰ Tr. 9930-31 (Hoolahan).

⁸¹¹ Tr. 9877-78, 9961 (Hoolahan).

488. Mr. Hoolahan indicated that he allowed his forecast to be guided by Mr. Hartz's restrictive interpretation of the term "legally deliverable."⁸¹² And he testified that he had analyzed only 12 of the 36 pools on the ANS because of time constraints.⁸¹³ These limitations further impacted the reliability of Mr. Hoolahan's estimates.

489. Mr. Hoolahan asserted that his results were comparable to Mr. Molli's results. However, Mr. Hoolahan was comparing his P2 case, which consisted of both proved and probable reserves, to Mr. Molli's proved reserves, and only after Mr. Hoolahan made a number of adjustments to Mr. Molli's calculations. This Court was not persuaded that Mr. Hoolahan's results were comparable to Mr. Molli's results.

490. Since ANS producers have access to field-specific information, internal industry information is very likely to assist forecasters in attaining the most reliable estimates regarding future ANS production and the volume of proven reserves that are likely to flow into TAPS during its economic life.⁸¹⁴ But the Owners have chosen not to offer into evidence or have their witnesses meaningfully review any internal reserves estimates and related documentation. This is despite the fact that a number of BP Pipelines and BP Exploration internal documents that were received through discovery were moved into evidence and discussed by the Municipalities' witnesses in their testimony at trial.

491. SARB observed the following in its Certificate of Determination for the 2007 assessment year:

The Board also found that the Owners failed to take advantage of the opportunity to provide the Division with persuasive data to challenge

⁸¹² Tr. 10070 (Hoolahan).

⁸¹³ Tr. 10070-71 (Hoolahan).

⁸¹⁴ Tr. 10450-51 (Molli).

the reserves estimates or throughput projections used by the Division if the Owners have such data. The Board found that the Owners chose not to the [sic] share information that the Owners and their parent companies possess regarding throughput and proven reserves with the Division or the Board and instead chose to present evidence and testimony from outside experts who did not have access to the information the Owners possess that was not already in the public record, and who lacked adequate direct experience with, or expertise about, the TAPS or the Alaska North Slope reserves.⁸¹⁵

492. The internal reserves and long term production forecasting information that was made available through discovery was not reviewed by two of the Owners' reserves witnesses, Mr. Hartz or Mr. Marks, and only cursorily reviewed by Mr. Hoolahan (and not synthesized into his analysis).⁸¹⁶ Further, Mr. Hoolahan did not have representatives of the Owners or their affiliated producers review his reserves estimates to provide feedback.⁸¹⁷ This is despite the fact that the internal reserves information presented at trial was substantially different from Mr. Hoolahan's conclusions. The fact that none of the Owners' reserves experts meaningfully addressed the BP internal reserves information at trial had a substantial negative impact on the weight this Court accorded to their testimony.

493. The failure of the Owners (and the Department) to address the confidential data provided in discovery is further demonstrated by the fact that neither party has submitted any proposed findings that require confidentiality.

494. The Owners maintain that any deficiency in this regard was remedied by the Department's access to and reliance upon highly confidential proven reserves information in

⁸¹⁵ MUN7-0234 at 15.

⁸¹⁶ Tr. 10162 (Hartz); Tr. 10403 (Marks); Tr. 10062 (Hoolahan).

⁸¹⁷ Tr. 10077 (Hoolahan).

the preparation of its forecasts.⁸¹⁸ This argument is unpersuasive. Having had the opportunity to compare the limited confidential data that the Department has received from the producers with the confidential reserves information that was received from BPXA in discovery, this Court is fully persuaded that the best available reserves information in this case is BPXA's confidential documentation with respect to those fields in which it has an interest, and not the documents produced to or maintained by the Department.⁸¹⁹

495. The determination of the estimated proven reserves should be assessed in light of the evidence available to, and presented by, each of the parties.⁸²⁰ The Owners did not persuasively rebut the Municipalities' evidence regarding proven reserves, including information contained in filings by the BP Royalty Trust and the confidential reserves information produced in discovery.

iv. The Department's Production Forecasts and Reserves Estimates Are Unreliable

496. Petroleum engineer Frank Molli performed a production forecast for the Department. The Assessor, Mr. Greeley, then made various adjustments to the forecast and also applied an economic test to it.

497. The Court finds that although Mr. Molli considered the three categories of proven reserves, his well-by-well analysis and methodology failed to capture significant barrels of oil that should be properly included in forecasts for each of the assessment

⁸¹⁸ Owners' Proposed Findings of Fact and Conclusions of Law ¶ 719.

⁸¹⁹ See, e.g., *Department's Proposed Findings of Fact and Conclusions of Law* ¶ 24 ("In the 2007 through 2009 assessments, the assessor sought information from the TAPS Owners and, as to reserves and production forecasting information related to their affiliate ANS producers, received very little.")

⁸²⁰ Alaska Civil Pattern Jury Instruction 02.23

years.⁸²¹ Mr. Molli also did not save all of the data necessary to permit a complete review of his work product.⁸²² And Mr. Molli did not prepare a forecast for each assessment year,⁸²³ but rather presented his forecast from the Fall 2010 Revenue Sources Book, which the Assessor then adjusted backwards for each of the three lien years.⁸²⁴

498. Consistent with his critique of Mr. Platt's use of b-factors over 1.0, Mr. Molli testified that he adjusted all of his b-factors to be no greater than 1.0.⁸²⁵ But at trial Mr. Molli was unable to articulate why he had set his b-factors at 1.0 as opposed to within the range prescribed by the authorities he relied on: "So why did you arbitrarily adjust your b factors greater than 1 down to 1 rather than .7?", Mr. Molli responded "That's a good question. I just left them at 1."⁸²⁶

499. Mr. Molli did not attempt to incorporate BPXA's internal forecasts into his analysis or use them to validate the reasonableness of his results.⁸²⁷ As with the Owners' experts, Mr. Molli's failure to do so had a substantial negative impact on the weight this Court accorded to his reserves analysis.

500. Mr. Greeley, without Mr. Molli's input, adjusted the data contained in Mr. Molli's forecast to retroactively produce proxy forecast figures for the three lien years.⁸²⁸ Mr.

⁸²¹ Tr. 9757-59 (Van Dyke) (confidential).

⁸²² Tr. 10472-43 (Molli) (confidential); Tr. 10543-45 (Molli).

⁸²³ Tr. 10532 (Molli).

⁸²⁴ Tr. 10446 (Molli); Tr. 10589-97 (Greeley) (confidential).

⁸²⁵ Tr. 10456 (Molli); Tr. 10548-50 (Molli); Tr. 9441-44 (Platt); MUN7-4360 at 2-5.

⁸²⁶ Tr. 10550 (Molli).

⁸²⁷ Tr. 10533-35 (Molli).

⁸²⁸ Tr. 10446 (Molli); Tr. 10587-88 (Greeley).

Greeley does not have a background in reservoir engineering or production forecasting.⁸²⁹ Mr. Greeley's reports did not explain the methodology he used to retroactively create the proxy forecasts for the assessment years, nor did he sufficiently explain that methodology at trial.⁸³⁰

501. Overall, this Court finds that Mr. Molli's Fall 2010 forecast, and the Assessor's adjustments to that forecast for each tax year, are considerably less reliable than the production forecast prepared by the Municipalities' witness Dudley Platt.

v. Conclusions on the Proven Reserves

502. BP Exploration (Alaska), an affiliated company of one of the taxpayers in this case, BP Pipelines, provides SEC reserves information on the Prudhoe Bay field each year to the BP Prudhoe Bay Royalty Trust.⁸³¹ The information is audited by an independent oil and gas consultant, Miller and Lents, before submission to the SEC.⁸³² The Trust's SEC filing for year-end 2005, using the SEC's heightened "reasonable certainty" standard for proven reserves, represented that "BP Alaska expects continued economic production [from Prudhoe Bay] at a declining rate until the year 2065"⁸³³ In the year-end 2006, 2007 and 2008 SEC 10-K filings, BP represented continued economic production at Prudhoe Bay until 2062, 2075 and 2049, respectively.⁸³⁴ The 2049 economic end-of-life calculation for December 31, 2008 was based on the price of oil on that date of \$44.60, while the

⁸²⁹ Tr. 10660-61 (Greeley).

⁸³⁰ Tr. 10592 (Greeley) (confidential).

⁸³¹ MUN7-0001 at 3000. See also 15 U.S.C. § 78ff(a) (up to \$15 million and 20 years in prison for a natural person, up to \$25 million for companies).

⁸³² MUN7-0001 at 3002.

⁸³³ MUN7-0001 at 3031.

⁸³⁴ MUN7-0001 at 3018, 3009, 2049.

December 31, 2006 economic end-of-life date was based on an oil price of \$61.06.⁸³⁵ Both of these amounts were considerably below the average price of oil during those years and its predicted future price.⁸³⁶ The 2007 filing was based on the price of oil on December 31, 2007 of \$96.01.

503. The following chart sets out the assumed end-of-life in the Prudhoe Bay Royalty Trust SEC filings and as calculated by each of the parties' experts.

Comparison of Prudhoe Bay End-of-Life Determinations

	CY 2007	CY 2008	CY 2009
PB Royalty Trust	2062 ⁸³⁷	2075 ⁸³⁸	2049 ⁸³⁹
Muni @ 100,000 bbl/d	2067 ⁸⁴⁰	2066 ⁸⁴¹	2068 ⁸⁴²
Muni @ Economic Limit	2075 ⁸⁴³	2075 ⁸⁴⁴	2075 ⁸⁴⁵
SOA @ 150,000 bbl/d	2040 ⁸⁴⁶	2040 ⁸⁴⁷	2040 ⁸⁴⁸
SOA @ Economic Limit	2043 ⁸⁴⁹	2044 ⁸⁵⁰	2053 ⁸⁵¹
Hoolahan – Initial	2026 ⁸⁵²	2033 ⁸⁵³	2021 ⁸⁵⁴
Hoolahan – Corrected	2046 ⁸⁵⁵	2053 ⁸⁵⁶	2032 ⁸⁵⁷

⁸³⁵ MUN7-0001 at 3000.

⁸³⁶ Tr. 8199-8202.

⁸³⁷ MUN7-0001 at 3018 (Dec. 31, 2006).

⁸³⁸ MUN7-0001 at 3009 (Dec. 31, 2007).

⁸³⁹ MUN7-0001 at 3000 (Dec. 31, 2008).

⁸⁴⁰ MUN7-4306 at 6.

⁸⁴¹ MUN7-4313 at 6.

⁸⁴² MUN7-4309 at 7.

⁸⁴³ MUN7-0024 at 19.

⁸⁴⁴ MUN7-0024 at 19.

⁸⁴⁵ MUN7-0024 at 19.

⁸⁴⁶ SOA7-7 at 18.

⁸⁴⁷ SOA7-7 at 19.

⁸⁴⁸ SOA7-7 at 20.

⁸⁴⁹ SOA7-113 at 1.

⁸⁵⁰ SOA7-114 at 1.

⁸⁵¹ SOA7-115 at 1.

⁸⁵² TO-07-0007.0151.

⁸⁵³ TO-07-0007.0152.

⁸⁵⁴ TO-07-0007.0152.

⁸⁵⁵ TO-07-0092 (corrected) at 10.

504. [CONFIDENTIAL – SEE SEALED ENVELOPE.] [REDACTED]

[REDACTED]

[REDACTED] [REDACTED] [REDACTED] [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

505. Using a 100,000 bbl/d minimum throughput limitation, this Court finds that the total proven reserves as determined by the Municipalities is the best available estimate as of each of the lien dates except that this Court will remove the production forecast for Point Thomson for 2007 and 2009, for the reasons expressed above. For 2007, subtracting Point Thomson reserves from the Municipalities' reserves calculations results in an end-of-life of 2065 for that year. Because of the timing of Point Thomson production in the 2009 forecast, removing that unit from the production forecast does not affect the end-of-life calculation for 2009 – it remains at 2068.⁸⁶³ For 2008, as noted above, the end-of-life based on a 100,000 bbl/d minimum capacity is 2066.

506. With Point Thomson removed from Mr. Platt's corrected reserves estimates for 2007 and 2009, the total proven reserves for each of the lien dates is as follows:

2007	7.812 billion barrels ⁸⁶⁴
2008	7.759 billion barrels ⁸⁶⁵
2009	7.077 billion barrels ⁸⁶⁶

3. Application of the Economic Age-Life Method

a. TAPS' Effective Age

507. The first step in the application of the economic age-life method requires a determination of the effective age of the property. An effective age estimate should consider

⁸⁶³ MUN7-4306 at 6; MUN7-4309 at 6.

⁸⁶⁴ MUN7-4306 at 6 (8.198 less .386 = 7.812).

⁸⁶⁵ MUN7-4313 at 6.

⁸⁶⁶ MUN7-4309 at 7 (7.362 less 284.6 = 7.0774).

the condition and utility of the property. If a property has received typical maintenance, its effective age and its actual age may be the same.⁸⁶⁷

508. TAPS began transporting oil in the summer of 1977. Thus, as of the lien dates its actual age was between 30 and 32 years.

509. TAPS is well-maintained. In 2001, the Owners asserted in the right-of-way renewal application that "TAPS' physical life is considered virtually unlimited given the execution of appropriate surveillance, maintenance, repair, and replacement programs."⁸⁶⁸ This Court finds that with continued prudent management of the pipeline and with routine investment in heaters should they be required, TAPS' physical life will extend for the duration of its projected economic life.

510. In recent years Alyeska has undertaken SR of the pumps. Alyeska also completed an upgrade of the ballast water treatment facility at the VMT during the lien years.⁸⁶⁹ Such extensive renovations and upgrading of TAPS have a significant positive effect on the physical condition of TAPS.⁸⁷⁰

\\
\\
\\
\\
\\
\\

⁸⁶⁷ *The Appraisal of Real Estate* at 412.

⁸⁶⁸ MUN7-8511 at 5 (Owners' Right of Way Renewal Application).

⁸⁶⁹ Tr. 3450 – 3456 (Stokes).

⁸⁷⁰ See *The Appraisal of Real Estate* at 414.

511. Based on the foregoing, this Court will make a one-year adjustment to the actual age of TAPS as of each lien date to arrive at its economic age, for the same reasons such an adjustment was made in the 2006 tax year proceeding.⁸⁷¹ With that one-year adjustment, the economic age-life depreciation percentage for TAPS for each year is:

$$\mathbf{2007:} \quad (2007 - 1977.5 - 1.0) / (2065 - 1977.5) = 28.5 / 87.5 = 32.57\%$$

$$\mathbf{2008:} \quad (2008 - 1977.5 - 1.0) / (2066 - 1977.5) = 29.5 / 88.5 = 33.33\%$$

$$\mathbf{2009:} \quad (2009 - 1977.5 - 1.0) / (2068 - 1977.5) = 30.5 / 90.5 = 33.70\%$$

512. This Court finds that using this effective age for TAPS reasonably captures all physical deterioration associated with the asset.

b. Additional Functional Obsolescence

513. Functional obsolescence is defined as obsolescence “caused by a flaw in the structure, materials, or design of the improvement when compared with the highest and best use of the most-effective functional design requirements at the time of appraisal.”⁸⁷²

514. The use of an appropriate replacement cost study eliminates “many, but not all, forms of functional obsolescence such as superadequacies and poor design.”⁸⁷³ One measure of the functional obsolescence arising out of excess capital costs is the “difference between the reproduction cost and replacement cost.”⁸⁷⁴

515. The Pro Plus replacement cost studies resolve much of TAPS’ functional obsolescence associated with excess capital costs. Evidence of this may be found by comparing the Pro Plus cost study to TAPS’ trended original reproduction cost based upon a

⁸⁷¹ See also Municipalities’ Proposed Findings of Fact and Conclusions of Law ¶ 744.

⁸⁷² *The Appraisal of Real Estate* at 434.

⁸⁷³ *The Appraisal of Real Estate* at 386.

⁸⁷⁴ *Valuing Machinery and Equipment* at 88.

construction index such as Marshall and Swift.⁸⁷⁵ SARB made such a comparison in 2009 and considered it a “valuable indicator.”⁸⁷⁶ Specifically, SARB noted that the Division’s calculation of a \$23.4 billion for 2009 based upon trending the original cost of TAPS using Marshall & Swift “compares favorably” with the \$19.8 billion Pro Plus RCN adopted by SARB for that lien year.⁸⁷⁷

516. Functional obsolescence may also arise from the need to expend excess operating and capital expenses for the subject property compared with the most economical similar new property that has the equivalent utility.⁸⁷⁸

517. The 2007, 2008, and 2009 Pro Plus RCN cost studies propose a replacement pipeline that is very similar to what TAPS is likely to look like when the pipeline SR is complete.⁸⁷⁹ Therefore, SARB reasonably relied on the projected costs in the actual SR pipeline plan to determine the necessary capital expenditures as well as excess operating costs to measure and calculate the current functional obsolescence.⁸⁸⁰ SARB tax-adjusted these projected SR costs and discounted them to arrive at the following present value amounts as of each lien date of the functional obsolescence associated with completion of pipeline SR and the ballast water treatment facility projects: \$242,639,688 in 2007,

⁸⁷⁵ MUN7-0227 at 8 (“The Department relied on its policy of consistently applying the Marshall and Swift annual petroleum cost index to update original costs for all oil and gas properties in Alaska, which it has done for more than 30 years.”)

⁸⁷⁶ MUN7-0236 at 31 (SARB 2009 Decision).

⁸⁷⁷ MUN7-0236 at 31 n.10.

⁸⁷⁸ *Valuing Machinery and Equipment* at 88.

⁸⁷⁹ However, the Pro Plus RCN has one more upgraded pump station than is currently planned on TAPS, which this Court has considered through scaling below.

⁸⁸⁰ 2009 R. 124-25. These figures were derived from the Alyeska Long Term Plan.

\$228,384,344 in 2008, and \$250,150,655 in 2009.⁸⁸¹ The Court adopts these costs and finds that they would not otherwise be captured through the economic age-life methodology.

518. The Owners assert that additional adjustments for functional obsolescence are required to reflect excess operating costs and excess capital costs associated with TAPS when compared with the 30-inch Stantec pipeline.⁸⁸² However, as detailed above, this Court has found that the 30-inch Stantec RCN pipeline is not a proper replacement property for TAPS. Therefore, a comparison of the operating costs between the existing TAPS and the Stantec RCN is not a proper measure of TAPS' functional obsolescence.

519. The Owners have also included the future costs of heaters as a functional obsolescence deduction. But to date, the Owners have made no decision as to the number, type, or manufacturer of heaters nor have any bids to acquire and install heaters been requested.⁸⁸³ While some amount of heaters seem likely to be required at some indeterminate point in the future, heaters were not required at all for the operation of TAPS during the lien years or today. The Owners failed to establish by a preponderance of the evidence that a functional obsolescence deduction for the future cost of heaters was warranted during the lien years. The cost, timing, and precise needs are too speculative to be considered when determining the economic value of TAPS from 2007 to 2009.

520. The Owners also seek functional obsolescence deductions for projected costs to replace the ballast water treatment facility, install internal floating roofs on the crude oil

⁸⁸¹ See MUN7-0234 at 12; MUN7-0235 at 18; R. 10669 (2009 SARB). See also MUN7-0035 at 51, 55, 59.

⁸⁸² TO-07-0004.0074-76 (functional obsolescence deduction for excess operating expenses); TO-07-0004.0076 (functional obsolescence deduction for excess capital expense).

⁸⁸³ TO-07-0004 at 75.

storage tanks, and modify the vapor recovery systems at the VMT.⁸⁸⁴ But the evidence at trial was inconclusive as to whether this list of projects would ever be sanctioned or built. Steven Schudel of Alyeska explained the status of potential reconfiguration at the VMT. He indicated that Alyeska was studying its options and awaiting an EPA ruling before determining how to proceed.⁸⁸⁵ He testified that option one “would retain the existing facilities and then you do whatever upgrades you have to do to comply with the [as yet un-promulgated EPA] regulations.”⁸⁸⁶ This Court finds that an adjustment for functional obsolescence for additional projects that may or may not be undertaken at the VMT is unwarranted for the 2007 to 2009 tax years.

521. This Court finds persuasive the Board’s determination on this issue in 2007, when the Owners put forward a list of proposed adjustments for functional obsolescence due to alleged inefficiencies in TAPS. In rejecting those adjustments, the Board held:

The Board concluded that, as of the assessment date, the timing and need for changes to the TAPS that form the basis for the Owners’ claims for the need to account for additional obsolescence due to low flow conditions and other factors are too speculative to require an additional downward adjustment to the TAPS value. The further that possible impacts on value of the TAPS are pushed out into the future, the less these future contingencies, such as adding additional reserves to future throughput or incurring additional costs, are likely to impact current value. The Board agreed with the Municipalities and the Division that an assessor should generally wait at least until a property owner has definite plans to incur specific costs before the assessor gives those projected costs much weight in making an estimate of value.⁸⁸⁷

⁸⁸⁴ See, e.g., T0-07-.0004.0076 (valuation as of Jan. 1, 2009).

⁸⁸⁵ Tr. 1349-1351 (Schudel).

⁸⁸⁶ Tr. 1350 (Schudel).

⁸⁸⁷ MUN7-0234 at 19-20. See also Amended Decision ¶ 433.

522. This Court also notes that appraisal theory directs that curable items of functional obsolescence be deducted from the RCN before the age-life ratio is applied to the RCN, and not after.⁸⁸⁸

c. Additional Economic Obsolescence

523. Economic obsolescence, or external obsolescence, is the loss of value of a property caused by factors external to the property.⁸⁸⁹

i. Scaling

524. This Court applied an economic age-life depreciation analysis in the 2006 tax year, and also held that an additional \$932 million of depreciation for economic obsolescence was warranted. Specifically, this Court held that “[w]hile TAPS is required to have a design capacity of at least 1.1 million bbl/d, the fact that capacity is not all being used to transport affiliated oil reduces the utility and value of TAPS as of the lien date.”⁸⁹⁰

525. When depreciating using the economic age-life method, this Court continues to find that application of scaling to TAPS is warranted because the economic age-life method would not otherwise capture all of the depreciation in TAPS that is attributable to its current superadequacy in relation to the proven reserves that are presently available to be transported on TAPS. Thus, while this Court has determined that an RCN must be of equivalent utility to TAPS – both in terms of the ability of the post-SR pumps to transport 1.1 million bbl/d and in terms of the 48-inch pipeline’s and VMT’s ability to handle capacities of up to 2.1 million bbl/d – that determination does not mean that this Court must or should disregard the fact that during the lien years, the throughput on TAPS was far less than those

⁸⁸⁸ *The Appraisal of Real Estate* at 422.

⁸⁸⁹ *Valuing Machinery and Equipment* at 67. See also *The Appraisal of Real Estate* at 391-92.

⁸⁹⁰ Amended Decision ¶ 439.

capacity levels such that the economic value of TAPS was less than it would have been had TAPS been transporting 2.1 million bbl/d during the lien years. Not to apply a scaling factor in these circumstances would result in an improper valuation of TAPS, particularly since the statute directs that economic value be determined with due regard to proven reserves, and not probable or potential reserves.

526. The Municipalities also assert that scaling physical facilities based upon capacity that is not obtainable without the additional expense of DRA is not appropriate. They assert that to do otherwise would scale the capacity created by DRA, which is an operating expense rather than a capital item. Thus, they assert that if scaling is applied now or in the future, it should only be calculated based only upon TAPS' actual mechanical capacity of 760,000 bbl/d.⁸⁹¹

532. This Court has given careful consideration to the appropriate application of scaling to TAPS so as to account for its economic obsolescence that results from its underutilization during the lien years. SARB has applied the scaling approach utilized by the Division in each of the lien years. Under that approach, an underutilization ratio was obtained by dividing the average daily throughput into the legally required capacity of 1.1 million bbl/d, using a scale factor of .45. The basis for the scale factor is found in a BP-generated analysis.⁸⁹²

533. Neither of the appealing parties met their burden of proof that the .45 scaling factor employed by the Division and accepted by the Board was improper.

⁸⁹¹ Municipalities' Proposed Findings of Fact and Conclusions of Law ¶ 791.

⁸⁹² See 2009 R. 6505-06.

534. This Court has discussed in detail when addressing the appropriate RCN to apply to TAPS that to be of equal utility to TAPS, an RCN must include the same design capacity that is currently specified for the pipeline and the VMT – 1.42 million bbl/d. Thus, while Pro Plus has asserted that its design basis for its RCN is 1.1 million bbl/d, the evidence demonstrates that capacity is derived from the number of installed pumps. The Pro Plus RCN 48-inch mainline pipe has the same capacity as the existing TAPS 48-inch pipeline, and the actual tank capacity at the existing TAPS VMT is comparable to the Pro Plus VMT, which is a design capacity of 1.42 million bbl/d. While this Court does find merit in the Municipalities' assertion that scaling to the 2.1 million bbl/d capacity achieved with DRA would be inappropriate, a scaling adjustment for underutilization of the 48-inch pipe and the VMT based on TAPS' existing capacity of 1.42 million bbl/d is warranted. The Division and SARB's use of 1.1 million bbl/d design as the denominator for those components of TAPS resulted in an improper valuation.

535. With respect to the pumps, the Municipalities have asserted that scaling, if used at all, should be based against the mechanical capacity of the existing TAPS of 760,000 bbl/d. But given that the Pro Plus RCN has one more SR pump station than the existing TAPS, this Court finds that scaling the pumps to a 1.1 million bbl/d capacity is warranted.⁸⁹³

536. The other applicable inputs to make this scaling deduction are as follows:

- Using the Pro Plus RCN, an average of approximately 8.7% of the direct costs are associated with the pump stations and meter stations during the three lien

⁸⁹³ See generally TO-07-0063.

years. The balance of the costs, or 91.3 %, is associated with the 48-inch mainline pipe and the VMT.

- The DOR projected throughput for TAPS during each of the lien years was as follows:⁸⁹⁴

2007 – 740,000 bbl/d

2008 – 731,000 bbl/d

2009 – 691,000 bbl/d

- A scaling factor is an exponential calculation, and thus results in less of a reduction than would occur with a percentage adjustment. Applying a .45 scaling factor to the above figures would result in the following additional percentage adjustments to the RCN after application of the additional functional obsolescence and the economic age-life calculation:

2007	Pipeline & VMT	25.4%
	Pump Stations	16.3%
2008	Pipeline & VMT	25.8%
	Pump Stations	16.8%
2009	Pipeline & VMT	27.7%
	Pump Stations	18.9%

ii. No Additional Economic Obsolescence Adjustment Is Warranted

532. The Owners assert that a significant additional economic obsolescence adjustment is warranted because TAPS is a regulated pipeline, and the effects of that regulation lower the pipeline's value.⁸⁹⁵ But they have produced no credible evidence that

⁸⁹⁴ MUN7-0018 at 13, 20, 27.

⁸⁹⁵ TO-07-0004 at 70-71.

establishes that the regulated status of TAPS has had any impact on the economic value of TAPS. This Court finds that TAPS would operate in much the same manner regardless of its regulated status. Tariff income that the Owners earn for shipping another producer's oil is in addition to the primary value that TAPS has for each Owner – the shipment of that Owner's affiliated oil.

527. The evidence persuasively demonstrated that TAPS was profitable as of each of the lien dates, and that it would be reproduced if it did not presently exist. There were over seven billion barrels of proven reserves remaining on the North Slope as of each lien date for 2007, 2008, and 2009 – an amount comparable to the estimated 9.6 billion barrels of proven reserves when TAPS began operation in 1977. The New York Supreme Court, Appellate Division has held that “[w]hile an allowance for economic obsolescence may be made when the property is not worth the reproduction cost, depending upon the earning capacity after production, it cannot be made in these circumstances where petitioner is profitable and the property would be reproduced. That petitioner is a regulated [pipeline] utility does not alter this conclusion.”⁸⁹⁶

528. The Owners' appraisal experts used what is termed an income shortfall method in an effort to calculate the percentage return differential between the projected tariff rate and a hypothetical unregulated rate, which was then discounted to present value.⁸⁹⁷ Using this approach, the Owners' appraisal expert, Mr. Remsha of American Appraisal, concluded that the income shortfall due to a buyer's inability to reset the rate base and collect a higher return is approximately \$1,030,000,000 in 2007, \$845,000,000 in 2008, and

⁸⁹⁶ *Tenneco, Inc. v. Town of Cazenovia*, 104 A.D.2d 511, 514 (N.Y. App. Div. 1984).

⁸⁹⁷ TO-07-0004 at 86, 115, 130.

\$730,000,000 in 2009.⁸⁹⁸ Terming that amount to constitute economic obsolescence, American Appraisal concluded that the value of TAPS under the RCNLD approach was identical to the value it concluded under the income approach of \$1.1 billion for 2007, \$1.2 billion for 2008, and \$1.3 billion for 2009.

529. This Court rejected this same application of an income shortfall method in the 2006 tax year proceeding that was advanced then by the Owners' expert appraiser, Ms. Spletter.⁸⁹⁹

530. Mr. Remsha acknowledged that if economic obsolescence in the form of income shortfall is applied, it makes no difference whether the RCN is \$10 billion or \$100 billion – the RCNLD would be identical using the income shortfall approach.⁹⁰⁰ Similarly, he testified that it did not matter whether the Pro Plus cost study or the Stantec cost study was used, the RCNLD would be the exact same result. Other appraisers persuasively testified that the effect of applying an income shortfall method is to eliminate the independent value of the cost approach by altering it to an income approach.⁹⁰¹

531. Aside from the conceptual circularity of the income shortfall approach, its particular application to TAPS is inappropriate for the same reasons that this Court has rejected the tariff income approach.⁹⁰² Since tariff income is not a driver of the economic

⁸⁹⁸ TO-07-0004 at 86, 115, 130.

⁸⁹⁹ Amended Decision ¶¶ 452-56.

⁹⁰⁰ Tr. 11914-15 (Remsha). See also Reilly Dep. 133 (June 2, 2011).

⁹⁰¹ Tr. 908-09 (Eyre); Tr. 12365-66 (Goodwin).

⁹⁰² See Tr. 12365-66 (Goodwin).

value of TAPS, its application to the cost approach is inappropriate. Mr. Eyre's testimony with regard to this topic was particularly helpful to the Court.⁹⁰³

532. The Owners did not present any new law or facts different from the 2006 tax year proceeding to support their use of a capitalized income shortfall method. This Court finds, as it did in the 2006 matter, that such a method should not be applied to determine economic obsolescence of TAPS.⁹⁰⁴

533. The Western State Association of Tax Administrators (“WSATA”) Appraisal Handbook rejects the income shortfall method:

A few appraisers attempt to measure obsolescence by comparing a company's actual earnings with the theoretical earnings that should have been achieved by the company with the assets on hand if they were earning a fair return on cost. This method is an improper variation of method often used for individual properties, where it can be demonstrated that the subject property is not technologically capable of producing as much operating income (cash flow) as new replacement property. When used to compare company earnings with theoretical company earnings, the method simply forces the cost approach to agree with the capitalized earnings approach.⁹⁰⁵

The WSATA Appraisal Handbook has wide acceptance by the approximately 35 states that do unit valuations and has undergone a comprehensive peer review process.⁹⁰⁶

\\

\\

\\

\\

⁹⁰³ Tr. 908-09 (Eyre).

⁹⁰⁴ Amended Decision ¶¶ 462-64.

⁹⁰⁵ WSATA Appraisal Handbook at 31 (Aug. 1989).

⁹⁰⁶ Tr. 11123-24, 11141-44 (Eyre).

534. Several appellate courts have also recognized that the income shortfall method is circular.⁹⁰⁷ As the New Jersey Supreme Court explained in *Transcontinental Gas Pipe Line Corp. v. Bernards Township*, a depreciated regulated pipeline has a value distinct from its tariff income that derives from its use:

Under the cost approach as it applies to special purchase property, the costs of a third person in acquiring the property is not the relevant inquiry; the very reason the cost approach is being utilized is that the property is so uniquely suited to its current use and user that a market sale to a third person is not an accurate indication of its value. Rather, the determination made in applying the cost approach is how much would a prudent person pay to replace the property. Since the people with the greatest interest in replacing special purchase property are the people for whom it was designed and built, and, in addition, are the people who must assume the cost of property taxation, the relevant question to ask in applying the cost approach to utility property is how much the ratepayers would pay to replace the property.⁹⁰⁸

535. In *Transcontinental*, the New Jersey Supreme Court also held:

The purposes of FERC regulation and ad valorem property taxation are drastically different: FERC is primarily concerned with ensuring that investors receive an adequate return on the property that has been invested. For such purposes, the original value of the property invested is an appropriate measure of value. For property tax purposes, however, it is necessary to determine the present cost of replacing the property. Under the cost approach, this is assumed to be the value of the property to the ratepayers, reflecting increases in construction costs, the current demand of consumers, availability and cost of alternate energy sources, and other factors. FERC's regulatory system reflects these factors only as of the time an asset enters the rate base; it makes no attempt to update them until an asset's functional lifespan is reached and it is eventually replaced at

⁹⁰⁷ See *United Tel. Co. of Nw., Inc. v. Dep't of Revenue*, 770 P.2d 43, 51 (Or. 1989) ("[a]djusting one approach to make it rely on the result or the same indication of value as another approach effectively eliminates a relevant perspective from consideration"); *Delta Air Lines, Inc. v. Dep't of Revenue*, 984 P.2d 836, 849 (Or. 1999); *Tenneco*, 104 A.D.2d at 514 ("It appears then that [the taxpayer's expert's] concept of economic obsolescence is nothing more than an attempt to convert the RCNLD approach into an income capitalization approach. This is not permissible."); see also *Tenn. Gas Pipeline Co., 766 A.2d at 675-76; Transcont'l. Gas Pipe Line Corp. v. Bernards Twp.*, 545 A.2d 746, 763 (N.J. 1988).

⁹⁰⁸ *Transcont'l. Gas Pipe Line*, 545 A.2d at 758 (citations omitted). See also Amended Decision ¶ 459.

current costs. Since depreciated original cost fails to reflect the value of all of the interests in utility property and undervalues those it does recognize, we decline to accept it as a true measure of a utility property's worth.⁹⁰⁹

536. Similarly, the Montana State Tax Appeal Board ("STAB") rejected the analysis of one of the Owners' experts in this case: "STAB rejected [Thomas] Tegarden's income shortfall approach because, among other reasons, it failed to account for income from properties that PacifiCorp had purchased with deferred income taxes" in 2005.⁹¹⁰ STAB also rejected the income shortfall method for its inaccuracies.⁹¹¹ In 2011, the Montana Supreme Court found that the STAB was entitled to deference regarding its determination that there was no economic obsolescence when the owners' entire case for economic obsolescence was premised on the income shortfall method.⁹¹²

537. An income shortfall adjustment is not appropriate for determining the full and true value of TAPS during the lien years at issue. The Owners failed to establish that the Division and SARB erred in refusing to apply the income shortfall method to determine economic obsolescence. Rather, if the income shortfall method was applied based on tariff income, the RCNLD valuation would no longer reflect the "full and true" economic value of TAPS as a critical component of the integrated ANS production and transportation system.

538. The record does not support the proposition that the regulatory status of TAPS negatively affects its economic value. Instead, the Court is fully persuaded that TAPS would continue to operate in much the same fashion as it does today whether it was subject to

⁹⁰⁹ *Transcont'l. Gas Pipe Line*, 545 A.2d at 760 (citations omitted). See also Amended Decision ¶ 460.

⁹¹⁰ See *Pacific Corp. v. State*, 253 P.3d 847, 848, 854-55 (Mont. 2011).

⁹¹¹ *Pacific Corp. v. State*, 253 P.3d at 855.

⁹¹² *Pacific Corp. v. State*, 253 P.3d at 854-55.

regulation or not. Each Owner's affiliated producer would be likely to continue to transport its oil on its affiliated pipeline space and would continue to pay the costs associated with such transportation. The record supports the proposition that the regulatory status of TAPS may positively shape its economic value. For example, the regulation of TAPS permits the Owners to share the costs associated with the operation of TAPS and realize a profit from independent shippers.⁹¹³ Dr. Cicchetti referred to this profit opportunity as the "icing on the cake."⁹¹⁴ Further, the regulatory status of TAPS also increases the value of each integrated enterprise by permitting each producer to deduct the tariff rate when calculating its royalty and production taxes to the State of Alaska.⁹¹⁵

539. This Court has given careful consideration to the fact that TAPS is regulated by both FERC and the RCA, and has concluded that the Owners have failed to demonstrate that the value of TAPS for purposes of ad valorem property taxation under AS 43.56 is negatively impacted by either its regulatory status or its current or projected tariff income. No additional adjustment for economic obsolescence is warranted.

C. RCNLD Conclusion of Value

540. This Court has found that the replacement cost new estimate of value for TAPS is \$17.645 billion in 2007, \$19.324 billion in 2008, and \$19.137 billion in 2009. Then functional obsolescence that is not captured under the economic age-life depreciation is deducted in the amount of \$242,639,688 for 2007, \$228,384,344 for 2008, and \$250,150,655 for 2009, as well as the value of the land and ROW of \$194 million each year.

⁹¹³ Tr. 8299-8301 (Cicchetti).

⁹¹⁴ Tr. 8300 (Cicchetti).

⁹¹⁵ Tr. 8252-53 (Cicchetti); Tr. 7721-23 (Toof).

From there, economic age-life depreciation based on an end-of-life calculation is applied of 32.57% for 2007, 33.33% for 2008, and 33.70% for 2009. Then an additional deduction for economic obsolescence based on scaling is made in the amount of \$2.856 billion for 2007, \$3.152 billion for 2008, and \$3.338 billion for 2009. Then the value of the land and the right-of-way are added back. The result is a total RCNLD of \$8.941 billion for 2007, \$9.644 billion for 2008, and \$9.249 billion for 2009.

VIII. THE INCOME APPROACH

A. The Integrated Income Approach to the Valuation of TAPS

541. The income approach determines the value of a property based upon the expected future benefits to its owner.⁹¹⁶ The principle of anticipation is fundamental to the income approach.⁹¹⁷

542. The income approach is generally used in valuing commercial business and properties that are bought and sold by investors because of the income they generate. The approach values the entire business entity. The income approach is not widely used by machinery and equipment appraisers because of "the difficulties in determining income that can be directly related to a specific asset, the concern for reliability of income forecasts, and a multitude of variables involved in this valuation approach."⁹¹⁸

⁹¹⁶ *Valuing Machinery and Equipment* at 159-60, 571.

⁹¹⁷ *The Appraisal of Real Estate* at 446.

⁹¹⁸ *Valuing Machinery and Equipment* at 159-60.

543. Since 2005 the Division and SARB have considered the income approach for TAPS multiple times, but have rejected it each time as an unreliable indicator of economic value.⁹¹⁹

544. When applying the income approach to a property that is a part of an integrated economic enterprise, an appraiser may consider the income generated by the entire integrated economic enterprise and then allocate a portion of that income and the resulting value back to the part of the integrated enterprise for which a value is to be determined.⁹²⁰ This integrated income approach is a form of unit valuation which is defined as the "evaluation of a group of integrated assets that are functioning as an economic unit."⁹²¹ Standard appraisal practice allows a unit to be composed of regulated and non-regulated properties.⁹²²

545. When deciding the proper unit to value, appraisers look at the integrated use of the business property.⁹²³ In particular, an appraiser looks to the physical, functional, and economic integration of the properties to determine the proper unit.⁹²⁴ In the case of TAPS, its integration with upstream properties makes the proper unit to value one that is composed of upstream and midstream Alaska properties.⁹²⁵

546. Brent Eyre, on behalf of the Municipalities, employed a discounted cash flow income approach to value the integrated economic unit of which TAPS is a part at \$40.2

⁹¹⁹ Tr. 12417-18 (Hoffbeck).

⁹²⁰ Tr. 11123 (Eyre).

⁹²¹ Tr. 11125 (Eyre).

⁹²² Tr. 11125 (Eyre).

⁹²³ Tr. 11128 (Eyre).

⁹²⁴ Tr. 11128-29 (Eyre).

⁹²⁵ Tr. 11128-31, 11134 (Eyre).

billion in 2007, \$44.2 billion in 2008, and \$50.4 billion in 2009.⁹²⁶ Dr. James Smith, on behalf of the Owners, testified that Mr. Eyre's unit value of the integrated ANS enterprise should be reduced by slightly less than 10% for each year, for a value of \$36.4 billion in 2007, \$41.1 billion in 2008, and \$46.0 billion in 2009.⁹²⁷

547. A commonly used factor for allocating unit value is invested cost, wherein the invested cost of the property subject to assessment is divided by the total amount of invested costs in the unit as a whole.⁹²⁸ After adjusting invested costs for inflation, Mr. Eyre determined that the allocated value of the whole unit to TAPS was approximately \$8.8 billion (21.9%) in 2007, \$9.6 billion (21.7%) in 2008, and \$10.7 billion (21.2%) in 2009.⁹²⁹

548. This Court was not persuaded that the integrated income approach should be relied upon to determine the economic value of TAPS for the lien years at issue, particularly where, as here, a comprehensive replacement cost new study has been accepted as modified by the Court, such that a considered application of the cost approach can be relied upon. The integrated income approach is more dependent upon volatile assumptions related to reserves, oil prices, and allocation than the cost approach. However, Mr. Eyre's valuation is a useful frame of reference and supports the assessed valuation of TAPS as determined by this Court for the lien years at issue. It also demonstrates that the tariff income approach advocated by the Owners fails to capture all elements of TAPS' economic value.

⁹²⁶ Tr. 11137 (Eyre).

⁹²⁷ Tr. 12073, 12082 (Smith).

⁹²⁸ Tr. 11137-38 (Eyre).

⁹²⁹ Tr. 11138-39 (Eyre).

B. The Tariff Income Approach Does Not Capture the Full and True Value of TAPS Under AS 43.56.060(e)(2)

549. As in the 2006 tax year litigation, the Court finds again that tariff income is not the primary driver of the economic value of TAPS under AS 43.56. As SARB has held, and as this Court has previously discussed in these findings, TAPS was not built or operated for tariff income, but to monetize the vast ANS reserves of the producer oil companies by bringing those reserves to market.⁹³⁰ In this regard Mr. Coulson, the President of BP Pipelines (Alaska) Inc. and the Chairman of the Owners' Committee for TAPS at the time, testified as follows:

Q: It's fair to say that TAPS was built by the producers?

THE WITNESS: Yes.

Q. And it's fair to say that TAPS was built - that the economic driver was the integrated economics of bringing the Alaska North Slope oil to market?

THE WITNESS: As I understand the history of TAPS, and indeed of most basin-opening developments, it's usually the resource owner that has to make the infrastructure development happen because of the risks associated with an undertaking like that.

Q. And the reason that the resource owner takes those risks is in order to monetize the resource and bring it to market, correct?

THE WITNESS: Yes.⁹³¹

550. The evidence also demonstrated that each Owner's interest in TAPS is a component of an integrated economic enterprise.⁹³²

⁹³⁰ Tr. 7729-30 (Toof); Tr. 8931 (Grasso) ("[T]he Owners aren't in the market to build a pipeline for its tariff income, but to get the – but to monetize the reserves on the North Slope."); Tr. 8482 (Brown); Tr. 8546-47 (Sullivan); Tr. 8249-50 (Cicchetti). See also Amended Decision ¶¶ 94, 471, 478.

⁹³¹ MUN7-0001 at 3767 (Coulson Dep.).

⁹³² Tr. 8249-65 (Cicchetti); Tr. 8539-40; 8546-8547 (Sullivan); Tr. 8891-92, 8934 (Grasso).

551. In contrast to Mr. Eyre's approach, which considered the income from the entire integrated economic enterprise, the Owners assert that the tariff income from TAPS, and only that income, is the appropriate proxy to capture the entire economic value of TAPS.⁹³³ The Owners' reliance upon the tariff income approach fails to recognize that TAPS was built, is operated, and would be replaced at an estimated cost of approximately \$19 billion if it were not in existence, not because of a desire to realize tariff income, but because of the overwhelming economic value arising from its highly integrated use for transporting ANS production to market.⁹³⁴

552. The Owners' position that the tariff income is a primary driver of the economic value of TAPS is at odds with the extensive system of crude oil pipelines on the ANS that are fully integrated with North Slope production and fully maintained but have no tariff income associated with their operation.⁹³⁵

553. In valuing TAPS for ad valorem purposes, the Department applied the cost approach without any reliance on the tariff income from 1977 to 1985, and then beginning again in 2005 to date.⁹³⁶ In 2001, the Department used a tariff-based income approach. For all the other years in between, the record suggests that the Department apparently relied upon a negotiation process that considered different valuation approaches including the tariff income approach, but many details of those negotiations have not been made available to this Court by either the Department or the Owners.⁹³⁷

⁹³³ TO-07-0004 at 0096, 0102, 0103, 0105.

⁹³⁴ Tr. 8249-65, 8299-8302 (Cicchetti); Tr. 8480-81 (Brown); Tr. 8546-47 (Sullivan); Tr. 8891-92 (Grasso).

⁹³⁵ Tr. 7851-52 (Marks); Tr. 12682-83 (Goodwin); Tr. 2725-26 (Falcone); Amended Decision ¶¶ 476.

⁹³⁶ Tr. 12691 (Goodwin); 2009 R. 483-84; Amended Decision ¶¶ 477.

⁹³⁷ Tr. 6816-17 (Greeley); MUN7-0234 at 4; Tr. 12419-20 (Hoffbeck).

554. The unique ownership structure of TAPS, the almost complete dependency of TAPS Owners on their affiliated and parent companies to build, operate, and improve TAPS, the use of TAPS by each Owner as part of its vertically integrated enterprise, and the history of ownership interests in TAPS all indicate that tariff income is not determinative of the economic value of TAPS.⁹³⁸ The sheer magnitude of the economic value realizable from the use of TAPS to monetize ANS reserves makes it far more likely than not that TAPS would continue to operate much as it does today or in 2007, 2008, or 2009, even if there was no tariff income at all.⁹³⁹

555. The tariff income approach incorrectly assumes that there would be a hypothetical buyer interested solely in the tariff income of TAPS to whom the TAPS Owners would agree to sell their interests. But the sales of ownership interests in TAPS have been to buyers that subsequently used TAPS as part of their integrated operations.⁹⁴⁰ The weight of the evidence demonstrates that there is not nor ever has been a market for TAPS based on its tariff income.⁹⁴¹ This is not unexpected considering the economic realities of developing isolated crude oil fields in Alaska. This Court finds that the tariff income approach proposed by the Owners is based on a fundamentally wrong premise of value, as it assumes that there is a willing buyer and a willing seller of TAPS based solely on its tariff income as a stand-alone investment.

⁹³⁸ Tr. 8255-57 (Cicchetti).

⁹³⁹ Tr. 12170 (Marks) (in response to the question of whether the TAPS Owners would operate TAPS even if they were not allowed tariff recovery, Mr. Marks responded, "I believe they would.").

⁹⁴⁰ Tr. 8878 (Marchitelli); Tr. 12682 (Goodwin); Huck Dep. at 147-49 (May 2, 2011).

⁹⁴¹ Tr. 8891 (Grasso); Tr. 8547 (Sullivan) (tariff income is not the driver of investments; access to the ANS reserves is the driver of TAPS investment decisions); MUN7-0001 at 3766-3767 (Coulson Dep.) (in response to the question whether Mr. Coulson was aware of any pipeline in Alaska that was built by a nonproducer, Mr. Coulson responded, "I am not aware of any.").

556. Tariff income is a regulatory, not an economic construct that has little place in determining the economic value of a pipeline used primarily for affiliated transportation.⁹⁴²

Likewise, the value determination of TAPS for ratemaking purposes is not the same as the value determination of TAPS for ad valorem tax purposes.

557. Several other courts have recognized the distinction between ratemaking and the determination of a property's value for ad valorem taxation purposes, both with respect to pipeline properties,⁹⁴³ as well as other types of properties.⁹⁴⁴ As the New Jersey Supreme Court in *Transcontinental Gas Pipe Line Corp. v. Bernards Township* explained:

⁹⁴² Tr. 8293-8294 (Cicchetti).

⁹⁴³ See *Questar Pipeline v. Utah State Tax Comm'n*, 850 P.2d 1175, 1178 (Utah 1993) (property tax appraisers of gas pipelines were within their rights when, after taking the consequences of FERC rate regulation into consideration, they did not alter their final opinions when adopting a method of valuation inconsistent with the FERC rate base value); *Transcont'l. Gas Pipe Line Corp.*, 545 A.2d 746 (1988) ("Courts in other states have long recognized a definite distinction between the valuation of public utility property for ratemaking purposes, determined pursuant to statutes applicable thereto, and the valuation of the same property pursuant to different statutes for ad valorem tax purposes.") (internal quotations omitted); *Mich. Wis. Pipe Line Co. v. Iowa State Bd. of Tax Rev.*, 368 N.W.2d 187, 191-192 (Iowa 1985) (board of tax review did not err in failing to set property tax of gas pipeline in a manner consistent with its FERC rate base even when evidence was offered that FERC rate base determined value for sales of comparable pipelines); *Mobil Pipeline Co. Rohmiller*, 522 P.2d 923, 936-937 (Kan. 1974) ("This issue, the regulations of earnings computed on a 'rate base,' was the major thrust of the public utility in attacking the assessment of its Kansas property in *Northern Natural Gas Co. v. Dwyer*, [492 P.2d 147 (Kan. 1971)]. The Court there recognized a definite distinction between the valuation of public utility property for rate making purposes, determined pursuant to statutes applicable thereto, and the valuation of the same property pursuant to different statutes for ad valorem tax purposes.").

⁹⁴⁴ *Matter of Long Island Lighting Co. v. Assessor for Town of Brookhaven*, 246 A.D.2d 156, 165 (N.Y. App. Div. 1998) ("[W]e note that we have previously held that a utility's rate base is an inappropriate factor to consider in the assessment of specialty property."); *S. Bell Tel. & Tel. v. Markham*, 632 So.2d 272 (Fla. Dist. Ct. App. 1994) (appraiser must consider effects of government regulation, *i.e.*, the rate base that controls earnings, under the controlling statute, but such regulation need not be determinative of property tax value), *Cent. Me. Power v. Town of Moscow*, 649 A.2d 320, 325 (Me. 1994) (The limit on return that an owner of dam utility property may earn on its investment because of its rate base is a factor that should be taken into account in valuation but is "emphatically not automatically determinative of the facility's just valuation" for property tax purposes.); *Consumers Power Co. v. Big Prairie Twp.*, 265 N.W.2d 182 (Mich. Ct. App. 1978) (the ad valorem assessing tax tribunal did not err in utilizing the adjusted depreciated reconstruction-cost method in assessing a dam rather than using the depreciated net cost value used by the FPC for ratemaking purposes), *superseded by statute*; *Pub. Serv. Co. of N.H.*, 377 A.2d at 125-126 ("[E]ven though net book value (original cost less depreciation) provides the rate base upon which plaintiff's rate of return is calculated, the value of the plant for tax purposes and the value for rate-making purposes need not be the same.") (internal quotations omitted); *Town of Barnet v. New England Power Co.*, 296 A.2d 228 (Vt. 1972) ("Fair market value should not rely upon one criterion and the values shown by the various methods of valuation

[T]he fact that FERC's regulatory scheme includes a value determination for its own [ratemaking] purposes does not bind municipalities to that figure for the purpose of ad valorem property taxation.⁹⁴⁵

558. For the foregoing reasons, this Court finds that a valuation of TAPS based upon its tariff income would not capture the full and true value of TAPS.

C. Tariff Income Is Not a Reliable Indicator of Economic Value

559. Even if tariff income was relevant to determining the economic value of TAPS, the projected future tariff income advanced by the Owners has not been demonstrated to be sufficiently reliable to determine the economic value of TAPS.

560. Under rate regulation, an owner is entitled to recover operating costs, a return of investment through a depreciation deduction, and a reasonable return based on unrecovered investment. Essentially, the return or profit from the tariff income is based entirely upon the unrecovered investment or rate base. In the case of TAPS, several experts testified that the original investment in TAPS has already largely been fully recovered through accelerated depreciation.⁹⁴⁶ Accordingly, the current return under the tariff income approach does not accurately reflect the economic value associated with the original investment in TAPS, as there is virtually no rate base or return under the tariff income approach associated with the majority of the existing TAPS' facilities.⁹⁴⁷ For

should be weighed and not averaged by the board. The bases of valuation for taxation purposes and for rate-making have been uniformly recognized as different.") (citations omitted).

⁹⁴⁵ 545 A.2d 746, 758 (N.J. 1988) (citation omitted); *County of Wayne v. Mich. State Tax Comm'n*, 682 N.W.2d 100, 126 (Mich. 2004); *Tenn. Gas Pipeline Co. v. Town of Hudson*, 766 A.2d 672, 675-676 (N.H. 2000) (holding that replacement-cost method, not the net-book-cost method, was the proper method for valuing the pipeline company's FERC-regulated property). See also Amended Decision ¶ 81.

⁹⁴⁶ Tr. 1212 (Marks) (testifying that "by the mid 90s it shows about 95 percent of TAPS had been depreciated under TSM. By the late '90s, essentially 100 percent of TAPS had been depreciated under TSM"). See also Tr. 7715-16 (Toof); Tr. 12421-22 (Hoffbeck); Tr. 12689-88 (Goodwin).

⁹⁴⁷ Tr. 12687-88 (Goodwin).

example, the original investment associated with the mainline pipe and VMT is almost fully recovered, such that there is little to no rate base associated with the economic contribution of either the mainline pipe or the VMT to the ongoing operations of TAPS.⁹⁴⁸ The current return on TAPS only reflects the additional investment associated with recent capital expenditures on TAPS such as the SR project.⁹⁴⁹ Thus, an income approach based on tariff income as advanced by the Owners would result in TAPS not being taxed at its full and true value.⁹⁵⁰

561. Historically, regulatory disputes concerning TAPS' tariff rates have most often been resolved by settlement among the parties rather than by a substantive determination by FERC or the RCA.⁹⁵¹ The settlement that has governed TAPS' tariff rates for the majority of the time it has been in service has been the TAPS Settlement Agreement ("TSA"). The TSA contained a complex and unique rate methodology referred to as the TSM. Both the State and the TAPS Owners supported the TSA. An Explanatory Statement by the State of Alaska and the Department of Justice in support of the settlement stated, "Alaska and DOJ believe that as a settlement, the tariff stream produced by the TSM is a fair and reasonable attempt to achieve a tariff profile that will encourage economically efficient exploration of North Slope petroleum resources."⁹⁵²

⁹⁴⁸ Tr. 12421-22 (Hoffbeck); Tr. 12687-88 (Goodwin).

⁹⁴⁹ Additions to the property used by a carrier to provide service will increase the rate base, the return on the rate base, and consequently the tariff income. In the case of TAPS, although the TAPS Owners made additional capital expenditures for TAPS in the SR project, the prudence of those expenditures is being challenged in the current joint rate proceeding before FERC and the RCA, and the rate effect of the SR expenditure is at this time unknown.

⁹⁵⁰ Tr. 12421-12422 (Hoffbeck); Tr. 12687-12688 (Goodwin).

⁹⁵¹ See, e.g., Tr. 8933 (Grasso).

⁹⁵² TO-07-0031.0119.

562. The RCA found that under the TSM, between 1977 and 1996, the TAPS Owners collected, in 1997 dollars, \$13.5 billion more than would have been collected under the current rate methodology used by the RCA to set rates on TAPS.⁹⁵³ Nevertheless, the TSM was approved by FERC.⁹⁵⁴

563. Settlements are approved by FERC under a fair and reasonable standard and in the public interest standard and not under a just and reasonable standard.⁹⁵⁵ FERC may also approve black-box settlements under which the rate is known but not the methodology used to calculate the rate.⁹⁵⁶ One of the Owners' regulatory experts, Dr. Toof, acknowledged that "settlement rates are a beast unto themselves."⁹⁵⁷

564. In 2005 and 2006, after the TSM had expired, FERC set just and reasonable rates under the Opinion No. 154-B methodology for 2005 of \$1.92 and for 2006 of \$2.02.⁹⁵⁸ Under FERC doctrine, however, the last "clean rate," meaning the last unprotested TSM rate for 2004, was used as the floor for refunds for 2005 and 2006.⁹⁵⁹ That rate was from \$3.00 to \$3.20.⁹⁶⁰ The TAPS Owners also filed for rate increases in 2007 and 2008, which were

⁹⁵³ MUN7-0001 at 1140, 1274, 1513-1516 (excerpts from RCA Order No. 151, Nov. 27, 2002) ("We now compare the past annual DOC revenue requirements . . . with the past annual TSM revenue requirements. Exhibit 7, Schedule 2 reveals that TSM has, on a cumulative basis, provided the Carriers with an opportunity to recover \$9.9 billion more than their costs as determined by the DOC revenue requirements. In 1997 dollars, the net present value of the cumulative stream of revenue requirement difference is \$13.5 billion . . ."); Tr. 8496-8500 (Brown); Tr. 8542-43 (Sullivan) ("The underlying principles in that TAPS Settlement Agreement provided for the highest return on any pipeline I have ever done an analysis on").

⁹⁵⁴ Tr. 7292 (Kelly).

⁹⁵⁵ Tr. 7292 (Kelly).

⁹⁵⁶ Tr. 7293 (Kelly).

⁹⁵⁷ Tr. 7730 (Toof).

⁹⁵⁸ *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 61,215 at ¶ 103, 115 (2008).

⁹⁵⁹ *BP Pipelines (Alaska) Inc.*, 125 FERC ¶ 226 (2008) (Op. No. 502).

⁹⁶⁰ *BP Pipelines (Alaska) Inc.*, 127 FERC ¶ 61,047 at ¶ 39 & n.37 (2009).

resolved under a “black-box” settlement.⁹⁶¹ The TAPS Owners’ filed rates for 2009 and 2010 are currently under litigation at FERC.⁹⁶²

565. The Owners have tried to predict future tariffs for the next several decades in order to determine the net present value of that tariff income stream to apply in this ad valorem tax case. The Owners presented the testimony of former FERC Commissioner Suede Kelly in support of their position that the FERC Opinion No. 154-B methodology is straightforward and can be used to predict net cash flow over the long term and that settlement rates on TAPS would not vary significantly from what would result under Opinion No. 154-B.⁹⁶³ However, Ms. Kelly did not opine as to what future tariffs this Court should apply under a tariff-based income approach. And although Ms. Kelly served as a FERC Commissioner, she had never been in a FERC hearing room on a TAPS matter.⁹⁶⁴ Ms. Kelly is currently an attorney whose law firm represents ExxonMobil Corporation⁹⁶⁵ and acknowledged that she was not an expert in ad valorem tax matters. At trial, in response to a question from the Court, Ms. Kelly answered that FERC could have abandonment authority over oil pipelines, but she subsequently corrected that testimony and stated that FERC had no such authority.⁹⁶⁶

⁹⁶¹ Tr. 8933 (Grasso). The TSA required the TAPS Owners to file yearly rates using the TSM. Tr. 7647 (Toof). The TSM ended in 2008. Tr. 7668 (Toof). The TAPS Owners have each filed for multiple rate increases in 2009 and 2010. See Tr. 8890-91 (Grasso). This process of filing multiple rate increases is known as “pancaking.” Amended Decision ¶ 492.

⁹⁶² Tr. 7667 (Toof).

⁹⁶³ Tr. 7211, 7212, 7216 (Kelly).

⁹⁶⁴ Tr. 7287-89 (Kelly)

⁹⁶⁵ Tr. 7258 (Kelly).

⁹⁶⁶ Tr. 7179-80, 7298-7303 (Kelly).

566. Ms. Kelly had no knowledge of how rates established under the TSM would compare to rates established under Opinion No. 154-B.⁹⁶⁷ Ms. Kelly did not know the specifics of the TAPS Owners' 2007-2010 rate filings at FERC and was not aware of the TAPS SR proceeding pending at FERC.⁹⁶⁸ Based on the foregoing, this Court was not persuaded by Ms. Kelly's testimony regarding FERC rate setting, including Opinion No. 154-B methodology and its application to determine TAPS' tariffs.

567. This Court was also unpersuaded by Dr. Toof's testimony that TAPS' tariffs have been stable and predictable.⁹⁶⁹ Dr. Toof has never sponsored an Opinion No. 154-B revenue requirement before the FERC.⁹⁷⁰ Dr. Toof has never prepared a rate filing and does not consider himself a rate of return expert.⁹⁷¹ Although Dr. Toof in the TAPS' FERC rate case took the position that the TSM produced just and reasonable rates, Presiding Judge Cintron, the Commission, and the Court of Appeals for the D.C. Circuit all disagreed with Dr. Toof's position on this issue.⁹⁷²

568. This Court finds that the regulatory status of TAPS is so unique that the projection of future tariffs for it would be less reliable and less predictable than for other regulated pipelines.⁹⁷³ When asked "Is there any crude oil pipeline in the United States that

⁹⁶⁷ Tr. 7295-96 (Kelly).

⁹⁶⁸ Tr. 7296-98 (Kelly).

⁹⁶⁹ Tr. 7681 (Toof).

⁹⁷⁰ Tr. 7704 (Toof).

⁹⁷¹ Tr. 7705-06 (Toof).

⁹⁷² Tr. 7706 (Toof).

⁹⁷³ Tr. 8539-8540 (Sullivan).

is in the unique regulatory status of TAPS [and the pipelines that feed into TAPS] before the FERC?" Dr. Toof responded, "They are carved out as an entity unto themselves."⁹⁷⁴

569. Mr. Grasso demonstrated the instability of the TAPS tariff by noting that the Owners recently filed testimony with FERC in support of their own filed rates that supported different rates than they had originally filed. Mr. Grasso explained:

To further - what I would say to undermine the stability of the 154-B, in 2009 the Owners filed tariff rates at the FERC between \$4.01 and \$4.10. That case, as you know, is now subject to a proceeding called the SR proceeding, strategic reconfiguration, of which a 154-B cost-of-service is one component.

Two years after the fact of 2009, testimony's [sic] filed in January of 2011 by the Owners to support their rates. Well, in January 2011, the rate that's supported for 2009 is \$3.88. So two years after the fact, when rates were filed and collected at the \$4.10 range, they're supporting \$3.88.

So, historically, it's tough to hit the mark using 154-B.⁹⁷⁵

570. This Court critiqued the TAPS Owners in the 2006 tax year proceeding for failing to advance a rate expert to support the Owners' tariff income assumptions.⁹⁷⁶ In this case, the Owners again did not advance an expert who could support their specific tariff income assumptions. Regulatory Economics Group, LLC. ("REG") performed the cost-of-service calculations for American Appraisal,⁹⁷⁷ which American Appraisal used to value TAPS based on the tariff income approach. But no witness from REG testified at trial. The Owners' rate experts at trial, Ms. Kelly and Dr. Toof, did not review or support REG's rate model or the rate calculations produced under that model.

⁹⁷⁴ Tr. 7715 (Toof).

⁹⁷⁵ Tr. 8891-92 (Grasso).

⁹⁷⁶ Amended Decision ¶ 488.

⁹⁷⁷ TO-7-0004.0102.

571. The REG rate calculations that American Appraisal used are not reliable. An example is the rate calculations for 2009. As discussed earlier, the TAPS Owners' FERC rate filings for 2009 ranged from \$4.01 to \$4.10 per barrel, and the rate advocated by the expert for the Owners in the 2009 FERC rate case is \$3.88 per barrel. But in this ad valorem tax case, the Owners are proposing far lower rates of \$3.07, \$3.40, \$3.03, and \$3.25 per barrel on January 1, 2009.⁹⁷⁸ The lower the projected tariff, the lower the net present value of the income stream.

572. Regulatory rate models are not intended to be used to predict future cash flows. Consistent with that reality, Dr. Toof declined to predict the outcome of the current TAPS' rate proceedings before FERC and the RCA.⁹⁷⁹

573. In sum, the evidence at trial persuasively demonstrated that TAPS' tariffs do not provide a stable or predictable foundation upon which to base the economic value of TAPS.⁹⁸⁰

574. SARB has repeatedly found that tariff income alone does not capture the economic value of the pipeline. As SARB explained in its 2007 Decision:

The value of a pipeline's tariff income stream is generally only a portion of the value of the pipeline. That portion is the value of the original investment, plus capital expenditures and a reasonable return on these outlays of capital, which make up the tariff rate base. The tariff regulatory process attempts to ensure that shippers pay the pipeline owners only once for the capital costs through their tariff payments. . . . The tariff is based on depreciated capital costs, not current market value as a stand-alone property or the pipeline's current value as part of an economic unit. A regulated tariff does not

⁹⁷⁸ TO-07-0004.0195; TO-07-0004.0208; TO-07-0004.0219; TO-07-0004.0232.

⁹⁷⁹ Tr. 7740-41 (Dr. Toof acknowledged that at his deposition he had declined to predict the outcome of the strategic reconfiguration case pending at FERC and the RCA, since he "was not in the prediction business.").

⁹⁸⁰ Tr. 8884-91 (Grasso).

produce an income that would capture the current economic value of the pipeline.⁹⁸¹

575. For all the foregoing reasons, and consistent with the determinations made by many other courts, this Court finds that the Owners have failed to demonstrate that the Division and SARB's use of the RCNLD approach and its rejection of a tariff income approach was unreasonable and unsupported by the record. Instead, the record clearly demonstrates that the use of the RCNLD methodology to value TAPS for ad valorem tax purposes is a fundamentally sound valuation determination.

IX. THE COMPARABLE SALES APPROACH

576. The third primary approach to valuation is the comparable sales approach. "In the sales comparison approach, the appraiser develops an opinion of value by analyzing closed sales, listings, or pending sales of properties that are similar to the subject property."⁹⁸²

577. The sales comparison approach is most reliable when there is an active market providing a sufficient number of sales of comparable property that can be independently verified through reliable sources.⁹⁸³ The "important concepts are 'active market' and 'verifiable information.'"⁹⁸⁴ The sales comparison approach "is not feasible when the subject property is unique" or "if an active market for that property does not exist."⁹⁸⁵

⁹⁸¹ MUN7-0234 at 16. See also MUN7-0235 at 15, 17; MUN7-0236 at 30.

⁹⁸² *The Appraisal of Real Estate* at 297.

⁹⁸³ *Valuing Machinery and Equipment* at 122.

⁹⁸⁴ *Valuing Machinery and Equipment* at 122.

⁹⁸⁵ *Valuing Machinery and Equipment* at 122.

578. It is uncontested that TAPS is a unique, limited-market and special purpose property.⁹⁸⁶

579. As explained by the Minnesota Supreme Court:

Because the [property] is specially adapted to a unique use and will not readily be sold to another user, the very nature of special purpose property is such that market value cannot readily be determined by the existence of an actual market, and therefore other methods of valuation, such as reproduction cost, must be resorted to Usually . . . comparable sales are not available for a [property] that is special use property. Nor is the income approach always directly relevant. Thus, where the owner is less interested in the income the property will generate than in occupying a [property] uniquely suited for the owner's special type of business, the reproduction cost minus depreciation method has been held to be appropriate for determining the market value of a [property], rather than an income approach.

Fed. Reserve Bank of Minneapolis v. State, 313 N.W.2d 619, 622 - 624 (Minn. 1981)
(quotations omitted).

580. *The Appraisal of Real Estate* specifies that a proper "market analysis and highest and best use analysis are fundamental to the sales comparison approach."⁹⁸⁷

581. The record demonstrates that sellers of an interest in TAPS sell when they no longer have an integrated use for TAPS. Similarly, the record demonstrates that buyers of an interest in TAPS buy only when they have an integrated use for TAPS.⁹⁸⁸ In short, the purchase and sale of interests in TAPS have been driven by each oil producing company's integrated economics rather than by tariff income.⁹⁸⁹

⁹⁸⁶ Tr. 11903 (Remsha); Loke Dep. 60 (June 1, 2011).

⁹⁸⁷ *The Appraisal of Real Estate* at 299-300.

⁹⁸⁸ Tr. 12682 (Goodwin).

⁹⁸⁹ Tr. 12682 (Goodwin).

582. Mr. Sullivan, on behalf of the Municipalities, persuasively discussed the fundamental differences between the transfer of pipeline interests in Alaska and the pipeline markets in the Lower 48.⁹⁹⁰ He noted that there is only one independent shipper on TAPS after 34 years of operation.⁹⁹¹ He compared the market dynamics of the ANS and TAPS with two major oil producing basins in the Lower 48, the North Dakota basin and the Gulf Coast basin. He explained that in those Lower 48 markets, the pipelines are not owned or dominated by affiliates of the oil producers. Instead there are hundreds of independent producers, shippers, and marketers in each of those basins.⁹⁹² The Court was persuaded that comparing sales from different markets with fundamentally different market drivers than those existing in Alaska or for TAPS is not helpful in framing the economic value of TAPS.

583. Other courts have recognized that the absence of comparable sales and a meaningful income stream typically result in the use of the cost approach for limited-use and special-purpose property.⁹⁹³

\\

\\

\\

\\

\\

\\

⁹⁹⁰ Tr. 8550-64 (Sullivan). See also Tr. 12311-12 (Podwalny); Tr. 12682 (Goodwin).

⁹⁹¹ Tr. 8539-40, 8562-64 (Sullivan).

⁹⁹² Tr. 8562-65 (Sullivan).

⁹⁹³ See, e.g., *Brooklyn Union Gas Co. v. State Bd. of Equalization*, 482 N.E.2d 77, 83 (N.Y. 1985); *Guild Wineries & Distilleries v. County of Fresno*, 51 Cal. App. 3d 182, 187-88 (Ca. Ct. App. 1975); *First Wis. Bankshares Corp. v. United States*, 369 F. Supp. 1034, 1039 (E.D. Wis. 1973).

584. As with the tariff income approach, the sales comparison approach has been repeatedly considered but determined not to be a reliable approach for determining the economic value of TAPS by both the Division and SARB. Thus, in 2007, SARB held that “there was no comparable property or representative sales of partial interests to make a reliable comparable sales valuation of the TAPS.”⁹⁹⁴ And in 2009 SARB found as follows:

The 2009 comparable sales value estimates could not be relied on due to the same problems that these valuations have suffered from since they were first considered in the 2001 TAPS assessment. There are no other pipeline properties that are similar enough to the TAPS to obtain an accurate assessed value from sales. The historical partial sales of the TAPS were not arms-length transactions and were not independent of other transactions between the buyer and seller. Grossing up small partial sales creates distortions in the values obtained.⁹⁹⁵

At trial, the Assessor agreed that the sales comparison approach should not be relied on by this Court due to a lack of comparables, and the partial interest sales of TAPS were old and uninformative.⁹⁹⁶

585. At trial, the Owners' appraiser Michael Remsha sponsored a sales comparison approach on behalf of the Owners for the years at issue.⁹⁹⁷ But Gary Loke and not Mr. Remsha was the appraiser for American Appraisal that did the work and drafted the relevant parts of the appraisal associated with the sales comparison approach.⁹⁹⁸ Mr. Loke was not offered by the Owners as a witness at trial. Mr. Remsha indicated he personally did not

⁹⁹⁴ MUN7-0234 at 17 (2007 SARB).

⁹⁹⁵ MUN7-0236 at 30 (2009 SARB).

⁹⁹⁶ Tr. 12982-84 (Greeley).

⁹⁹⁷ Tr. 11845-51 (Remsha).

⁹⁹⁸ Tr. 11895-96 (Remsha).

investigate or verify the sales that were used in the sales comparison approach.⁹⁹⁹ Mr. Remsha indicated Mr. Loke would have been the best person to answer questions about American Appraisal's sales comparison approach.¹⁰⁰⁰

586. For a sales comparison approach to be helpful, the sales need to be compared with the subject and "[i]f the comparable sale is not identical to the subject, the selling price of the comparable *must* be adjusted to indicate what the selling price of the comparable would have been if the comparable had been identical to the subject."¹⁰⁰¹ There are several elements of comparability that must be considered when adjusting the selling price of the comparable back to the subject including age, condition, capacity, features, location, motivation of the parties, price, quality, time of sale, and type of sale.¹⁰⁰²

587. Mr. Loke looked at fourteen Lower 48 pipeline sales, and used an earnings multiples analysis to project value to TAPS based on these sales. He did not make any other adjustments so as to compare these properties to TAPS.

588. With regard to these fourteen transactions, American Appraisal did not speak with the seller or buyer, or otherwise independently verify or confirm the transaction details.¹⁰⁰³ This failure to verify was the case even where BP was a party to the transaction.¹⁰⁰⁴ Mr. Loke did not know whether any of the fourteen sales transactions were due to merger and acquisition regulatory requirements.¹⁰⁰⁵ Mr. Loke was apparently

⁹⁹⁹ Tr. 11896 (Remsha).

¹⁰⁰⁰ Tr. 11895-97 (Remsha).

¹⁰⁰¹ *Valuing Machinery and Equipment* at 124 (emphasis added).

¹⁰⁰² *Valuing Machinery and Equipment* at 126-128.

¹⁰⁰³ Loke Dep. 74-75, 86-87, 104-05 (June 1, 2011).

¹⁰⁰⁴ Loke Dep. 86-87 (June 1, 2011).

¹⁰⁰⁵ Loke Dep. 95-96 (June 1, 2011).

unaware that Transaction No. 14 was between related parties until he learned of that detail from comments made by Mr. Connolly at his deposition.¹⁰⁰⁶

589. Of the fourteen sales transactions considered, only four were deemed by Mr. Loke to be relevant as an indicator of value for TAPS.¹⁰⁰⁷ The sales prices of the four selected transactions ranged from a high of \$2.4 billion to a low of \$158 million.¹⁰⁰⁸ Mr. Loke did not consider any of the four selected sales to be limited market properties and, as noted above, made no adjustments to those sales in an effort to reflect comparability with TAPS.¹⁰⁰⁹

590. Mr. Loke testified that he had a “very challenging time” finding public domain information with regard to transfers of fractional TAPS’ interests.¹⁰¹⁰ He relied on information that he received from counsel for the Owners, but acknowledged that obtaining information in this manner was not a standard or common practice.¹⁰¹¹

591. One of the Owners’ other appraisal experts, Thomas Tegarden, testified at trial that he “would agree there is a lack of comparable sales.”¹⁰¹²

592. The weight of the evidence presented at the trial de novo demonstrates that there are no comparable sales that inform the economic value of TAPS.

¹⁰⁰⁶ Loke Dep. 69-70 (June 1, 2011).

¹⁰⁰⁷ Loke Dep. 98 (June 1, 2011).

¹⁰⁰⁸ TO-07-0004 at 89 (American Appraisal); Loke Dep. 67-68 (June 1, 2011).

¹⁰⁰⁹ Loke Dep. 101 (June 1, 2011).

¹⁰¹⁰ Loke Dep. 103-107 (June 1, 2011).

¹⁰¹¹ Loke Dep. 103-107 (June 1, 2011).

¹⁰¹² Tr. 10313 (Tegarden).

X. RECONCILIATION AND CONCLUSION

593. USPAP does not require reliance upon any particular method of appraisal.

Instead, it provides as follows:

In developing a real property appraisal, an appraiser must reconcile the quality and quantity of data available and analyzed within the approaches used, and reconcile the applicability or suitability of the approaches used to arrive at the conclusion(s).¹⁰¹³

594. The record before this Court reflects that the Division and SARB carefully considered each of the three major approaches to value, as well as the fact that TAPS is a regulated pipeline. No party has demonstrated that reliance on the cost approach was improper, or unsupported by the record, or constituted a "clear adoption of a fundamentally wrong principle of valuation."¹⁰¹⁴

595. This Court has also carefully considered each of the three approaches to value – the cost approach, the income approach, and the sales approach. Based upon all of the evidence presented to this Court over the course of the nine-week trial de novo concerning the assessed value of TAPS from 2007 to 2009, this Court will rely solely on the cost approach for the 2007, 2008, and 2009 assessments.

596. For the reasons discussed in Section VII of this decision, this Court relies on the Pro Plus cost study for the valuation for TAPS, as adjusted herein.

597. This Court has been presented with considerably more evidence than was before either the Division or SARB, including extensive cross-examination of all of the experts and other witnesses, and has concluded that in certain respects, SARB's 2007, 2008, and 2009 valuation of TAPS resulted in an improper valuation of TAPS, particularly

¹⁰¹³ USPAP Standard 1- 6.

¹⁰¹⁴ See *N. Star Alaska Hous. v. Bd. of Equal.*, 778 P.2d 1140, 1144 n.7 (Alaska 1989).

with regard to the amount of the RCN, the amount of the scaling adjustment, and the lower limit of TAPS' capacity. Also, evidence at trial persuasively demonstrated that the life of TAPS based on its proven reserves and incorporating its minimum capacity throughput limitations as of the lien dates for 2007, 2008, and 2009 is at least until 2065.

598. Based on the foregoing, the following is a summary of this Court's determination of the assessed value for TAPS as of January 1, 2007, 2008 and 2009,¹⁰¹⁵ set forth in millions of dollars:

<u>Jan. 1, 2007</u>	<u>Jan. 1, 2008</u>	<u>Jan. 1, 2009</u>	
\$17,645	\$19,324	\$19,137	Replacement Cost New (RCN)
(\$194)	(\$194)	(\$194)	<i>Less Land & ROW</i>
(\$243)	(\$228)	(\$250)	<i>Less Additional Functional Obsolescence</i>
\$17,208	\$18,902	\$18,693	RCN Less Land & ROW & Additional FO
(\$5,605) 32.57%	(\$6,300) 33.33%	(\$6,300) 33.70%	<i>Less Economic Age-Life Depreciation</i>
\$11,603	\$12,602	\$12,393	RCN Less Economic Age-Life Depreciation
(\$2,691)	(\$2,968)	(\$3,134)	<i>Less Scaling of Pipe and VMT</i>
(\$165)	(\$184)	(\$204)	<i>Less Scaling of Pumps</i>
\$8,747	\$9,450	\$9,055	RCN Less All Depreciation
\$194	\$194	\$194	<i>Plus Land & ROW</i>
\$8,941	\$9,644	\$9,249	TOTAL RCNLD (in millions)

¹⁰¹⁵ The Court's Amended Decision ¶ 509, as well as SARB's decisions in 2007 and 2008, see, e.g., MUN7-0236 at 13, 15, had deductions for certain non-taxable assets and the Valdez Terminal Office building. Because those assets were not included in the Pro Plus Study, the adjustments are no longer necessary.

The primary reasons for the variations from year to year are due to market changes in the estimates made by Pro Plus in its RCN for the cost of steel and labor rates as of each of the lien dates.

599. This matter concerns the assessed valuation of TAPS as of January 1, 2007, 2008, and 2009. It is before the Superior Court pursuant to a specific statute that accords to taxpayers and affected municipalities the right to a trial de novo before the Superior Court of an administrative determination of the value of pipeline property.¹⁰¹⁶ Pursuant to that statute, this Court conducted a non-jury trial lasting approximately nine weeks in the fall of 2011. For the reasons expressed herein, this Court finds that as of January 1, 2007, 2008, and 2009, the "full and true value" of the Trans Alaska Pipeline System, "with due regard to the economic value of the property based on the estimated life of the proven reserves of gas or unrefined oil then technically, economically, and legally deliverable into the transportation facility"¹⁰¹⁷ is \$8.941 billion for 2007, \$9.644 billion for 2008, and \$9.249 billion for 2009.

ENTERED at Anchorage, Alaska this 30th day of December 2011.

Sharon L. Gleason
SHARON L. GLEASON
Superior Court Judge

I certify that on 12.30.11
a copy was mailed to each of the following
at their address of record:

Anna Masner
Judicial Assistant / Deputy Clerk

Seedorf, Mahoney, Palumbo, Garatoni, Gabel,
Diemer, Johnson, Long, Richards, Brena, &
Broder

¹⁰¹⁶ AS 43.56.130(i).

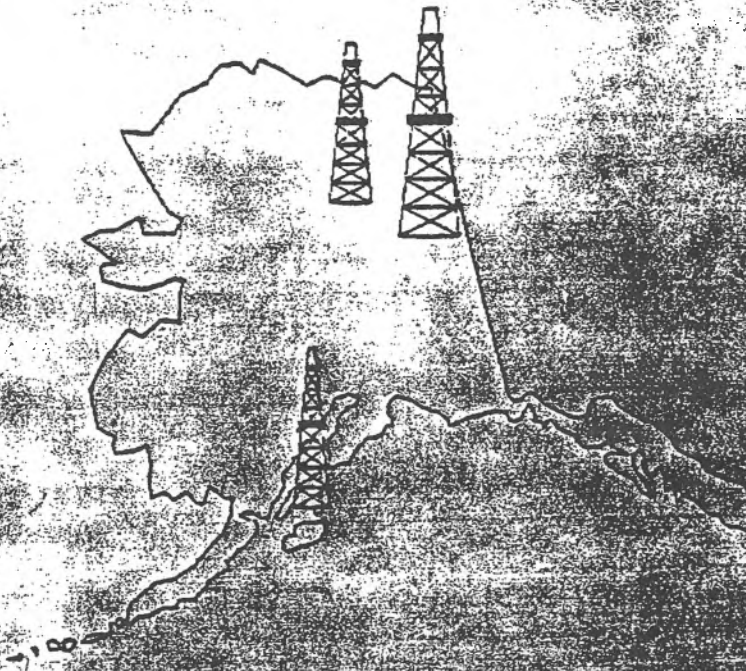
¹⁰¹⁷ AS 43.56.060(e)(2).

17.

**Oil Industry
Profitability in
Alaska 1969
through 1987**

Oil Industry Profitability in Alaska

1969 through 1987



Prepared for the Department of Revenue
State of Alaska

by

Edward E. Beal

Distinguished Enterprise Professor and
Director, Institute of Petroleum Accounting
University of North Texas

Price Waterhouse Centennial Professor of Accounting
University of Texas

March 15, 1989

RTSXMB 519667

Confidential Pursuant to
APUC Order P-97-4(22)

Exh # 115-RGV-E

REGULATORY COMMISSION OF ALASKA
P-97-4/P-97-7




EMP006-002296

R&R Court Reporters, Inc. Anchorage, Alaska
(907) 277-0572

From the desk of

LANCE M. WILLOUGHBY

PLEASE RETURN TO 

Confidential Pursuant to
APUC Order P-97-4(22)

RTSXMB 519669

T-33000099

Edward E. Deakin is the Distinguished Emergent Professor at the University of North Texas in Denton, Texas. He directs the Institute of Petroleum Accounting there. He is on leave from his position as the Eric Waterhouse Centennial Professor of Accounting at the University of Texas and has also held professorial posts at Stanford University and the University of Illinois. Professor Deakin has written more than fifty articles and books, many of which address issues of the oil and petroleum accounting industry. He has testified to the U.S. House of Representatives, Interior, and Treasury Committees on industry practices and has analyzed several major government reports on the industry. He has also analyzed numerous private company financial statements and has been a frequent speaker at industry seminars. He is a past president of the American Accounting Association and a past president of the American Petroleum Accounting Association. He is also a past president of the American Institute of Certified Public Accountants.

Confidential Pursuant to APUC Order P-97-4(22)

RTSXMB 519668

SUMMARY

Total Profit. The oil industry received an estimated \$42.6 billion in profit from production and transportation activities in Alaska from 1969 through 1987. The \$42.6 billion represents amounts accruing to producers after accounting for all expenses, including exploration, lease acquisition and income taxes, and allowing for recovery of investment costs (depreciation). The main section of this report presents details of profit for each calendar year. The technical section of this report describes each component of the profit, investment and cash flow elements. Below is a summary statement.

Total Alaska Oil Profit 1969 through 1987 (billions of dollars)

Revenues:		
Production revenues	\$ 97.6	
TAPS revenues	33.7	
Total Revenues		\$131.3
Expenses:		
Depreciation	12.1	
Operating Expenses	9.1	
Exploration Expenses	4.1	
Overhead	.8	
Interest	7.5	
Royalty	11.8	
Severance Taxes	10.4	
Property Taxes	3.5	
State Income Taxes	3.6	
Windfall Profit Taxes	6.4	
Federal Income Taxes	19.4	
Total Expenses		<u>88.7</u>
Profit		<u>\$ 42.6 Billion</u>
Profit per barrel: <u>\$6.59</u>		

Alaska North Slope (ANS) production contributed \$29.1 billion to profit, with \$27.8 billion of this amount attributable to Prudhoe Bay and \$1.3 billion

attributable to Kuparuk. TAPS provided \$12.4 billion. Production in Alaska other than ANS production added \$1.1 billion in profit. (Lisburne is included with Prudhoe Bay and Milne Point with Kuparuk. Endicott did not have significant production until after 1987. Alaska production other than ANS production is at Cook Inlet).

Shares. The \$42.6 billion in after-tax profit that accrued to the oil industry compares to \$29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were \$25.8 billion from these activities.

Investment. From 1969 through 1987, the industry invested \$25.0 billion in ANS development costs and for TAPS. \$13.1 billion of this represents the initial costs of Prudhoe Bay and TAPS. Of the \$25.0 billion investment, \$11.6 billion has been recovered through depreciation charges (\$6.6 billion from Prudhoe, \$1.0 billion from Kuparuk and \$4.0 billion from TAPS).

Rates of Return on Investment. Cash flows from all Alaska investments from 1976 through 1987, assuming no debt, total \$61.3 billion (\$41.8 billion of profit plus \$12.0 billion of depreciation plus \$7.5 billion of interest¹). Comparing these cash flows to the investment amounts over time implies that the after-tax rate of return on Alaska investments has been 29.7% from 1976 through 1987. Assuming that 75% of the initial investment was borrowed, an assumption that is indicated by available data, the rate of return on the investment is 43.7% after tax.

¹Interest is added back under the assumption of no debt because there would be no interest expense if the entire project were funded with equity. This analysis incorporates all ANS investments prior to 1976 into 1976 and 1977. A more detailed timing of these investments was beyond the scope of this study. As indicated in the technical discussion, the effects of this assumption create minimal changes in the results.

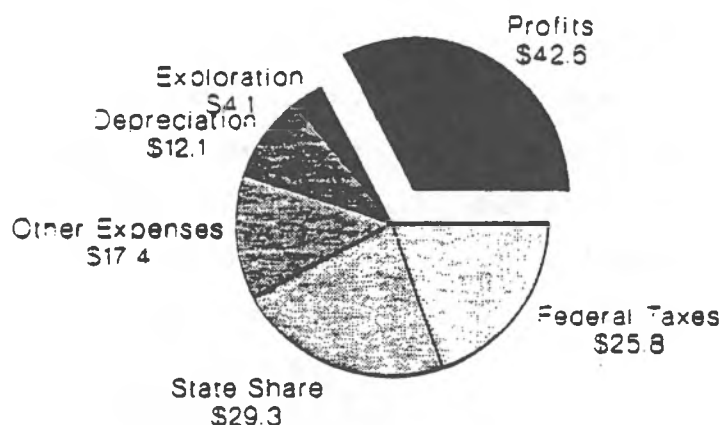
These rates of return compare to the long run rate of return on the New York Stock Exchange of 10% *before tax*. [*Wall Street Journal* (February 20, 1989)] The prime rate peaked at 21.5% *before tax* in 1982, but that was an exceptional year. During this period, a prime rate of 10% to 18% *before tax* was more typical. Using an average effective tax rate of 36%, which approximates the tax rate observed in this study, the equivalent after-tax return on the New York Stock Exchange is 6.4%. The equivalent peak prime rate after an effective tax rate of 36% is 13.76%.

Reinvestment of Alaska Cash Flows. Subsequent to the initial investment for Prudhoe Bay field and TAPS, the industry invested \$15.8 billion for ANS development and exploration throughout Alaska from 1978 through 1987. This includes \$3.9 billion in exploration expenses which are not included in the analyses of profits from individual fields. The reinvestment rate has been 27.8% of cash flows received during this period.

Seventy-five sources of data about Alaska oil operations were researched to develop this report. Although details do not exist on each and every data item, the information available in the references is sufficient to develop a reasonably accurate picture of industry profit. A study of the data suggests that the actual profit number could be as low as \$41 billion or as high as \$47 billion. The estimate reported here is at the conservative end of this range.

Figure 1 graphs the relationship among the revenues, expenses and profit for all Alaska oil production and transportation activities.

Figure 1
Revenues, Expenses and Profit
All Alaska Oil Activities
 (billions of dollars)



The \$42.6 billion in profit is what the producers received after accounting for all expenses, including exploration, lease acquisition, and after allowing recovery of the costs of investments in Alaska oil activities related to the useful lives of the investments.¹

From 1977 through 1987, virtually all of these profits were earned from the Alaska North Slope (ANS). ANS production contributed \$29.1 billion to profit, with \$27.8 billion of this amount attributable to Prudhoe Bay. Total production profit for the Prudhoe Bay field is given in Table 2.

¹Details of how the profit estimates were obtained are provided in the technical discussion. Some of the amounts could not be readily determined from publicly available data or the data were ambiguous. In these situations, a conservative approach was taken. As a result, this report gives a low-end estimate of oil industry profits. Throughout this report, the sum of the individual numbers may not add to identical totals due to rounding.

Oil Industry Profit in Alaska: 1969-1987 Overview

How profitable is the oil industry in Alaska? This is a question of major significance to the State of Alaska and to its residents because the State's share of the revenues from oil production and transportation activities are a primary factor in determining the State's General Fund revenues as well as the additions to the Permanent Fund. This report looks at available information on industry activities in Alaska to derive a picture of the profit attained from these activities. The results of the study indicate that the oil industry received \$42.6 billion in after-tax profit from 1969 through 1987 from oil production and from TAPS. The components of this profit estimate are given in Table 1:

Table 1
Total Alaska Oil Profit
1969 through 1987
(billions of dollars)

Revenues:		
Production revenue	\$ 97.6	
TAPS revenue	33.7	
Total Revenues		\$131.3
Expenses:		
Depreciation	12.1	
Operating Expenses	9.1	
Exploration Expenses	4.1	
Overhead	.8	
Interest	7.5	
Royalty	11.8	
Severance Taxes	10.4	
Property Taxes	3.5	
State Income Taxes	3.6	
Windfall Profit Taxes	6.4	
Federal Income Taxes	19.4	
Total Expenses		<u>88.7</u>
Profit		<u>\$ 42.6 Billion</u>
Profit per barrel: <u>\$6.59</u>		

Table 2
Total Prudhoe Bay Production Profit
1977 through 1987
 (billions of dollars)

Production Revenue	\$ 83.5
Less Expenses:	
Depreciation	6.6
Operating Expenses	4.4
Overhead	.7
Interest	1.3
Royalty	10.0
Severance Taxes	9.9
Property Taxes	1.4
State Income Taxes	2.5
Windfall Profit Taxes	5.9
Federal Income Taxes	<u>13.0</u>
Profit	<u>\$ 27.8 Billion</u>

Profit per barrel: \$5.81

Figure 2 shows the division of these revenues, expenses and profit.

Figure 2
Revenues, Expenses and Profit
Prudhoe Bay Production
 (billions of dollars)

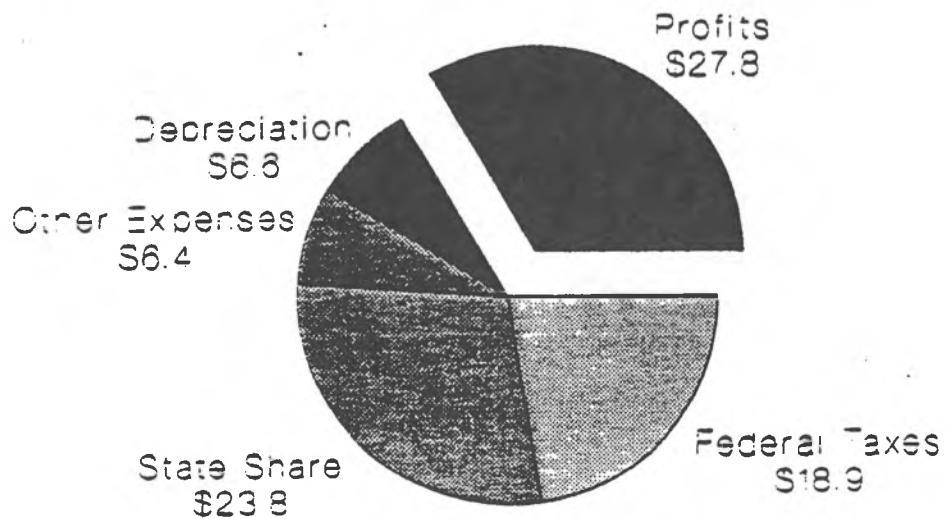


Table 3 shows Prudhoe Bay production profit for the oil producers on a year-by-year basis from 1977 through 1987.

Table 3
Profit from Prudhoe Bay Production
(millions of dollars)

1983 - 1987:

	1987	1986	1985	1984	1983
Production Revenue	\$6,573	\$4,327	\$9,847	\$10,097	\$10,079
Expenses:					
Depreciation	1,074	1,110	873	710	632
Operating Expenses	740	514	535	578	394
Overhead	109	104	139	89	93
Interest	146	139	141	119	119
Royalty	787	518	1,179	1,209	1,207
Severance Taxes	787	571	1,300	1,333	1,331
Property Taxes	150	148	150	148	147
State Income Taxes	83	37	165	171	172
Windfall					
Profit Taxes			39	211	426
Federal Income Taxes	917	0	2,212	1,469	1,756
Profit	<u>\$1,780</u>	<u>\$1,186</u>	<u>\$3,114</u>	<u>\$4,061</u>	<u>\$3,801</u>
Profit per barrel:	<u>\$3.55</u>	<u>\$2.40</u>	<u>\$6.25</u>	<u>\$8.26</u>	<u>\$7.75</u>

1977 - 1982:

	1982	1981	1980	1979	1978	1977
Revenue	\$11,271	\$13,330	\$9,541	\$5,892	\$1,849	\$ 717
Expenses:						
Depreciation	581	510	476	320	254	38
Operating Expenses	504	546	182	184	157	46
Overhead	77	51	15	2	0	2
Interest	139	17	10	156	203	117
Royalty	1,350	1,596	1,143	706	221	86
Severance Taxes	1,488	1,291	924	622	195	76
Property Taxes	147	146	146	123	104	30
State Income Taxes	168	669	550	367	67	30
Windfall Profit						
Taxes	1,375	3,089	797			
Federal Income Taxes	2,125	1,971	2,086	383	9	32
Profit	<u>\$3,315</u>	<u>\$3,443</u>	<u>\$3,212</u>	<u>\$3,030</u>	<u>\$ 639</u>	<u>\$ 260</u>
Profit per barrel:	<u>\$6.78</u>	<u>\$7.09</u>	<u>\$6.61</u>	<u>\$7.39</u>	<u>\$1.84</u>	<u>\$2.58</u>

Total revenues, costs and profit from Alaska production activities from 1969 to the end of 1987 are given in Table 6.

Table 6
Total Alaska Production Profit
1969 through 1987
 (billions of dollars)

Production Revenue	\$ 97.6
Less Expenses:	
Depreciation	8.1
Operating Expenses	5.3
Exploration Expenses	4.1
Overhead	.8
Interest	1.7
Royalty	11.8
Severance Taxes	10.4
Property Taxes	1.8
State Income Taxes	2.7
Windfall Profit Taxes	6.4
Federal Income Taxes	<u>14.3</u>
Profit	<u>\$ 30.2 Billion</u>
Profit per barrel: \$4.96	

A graph showing the distribution of these revenues, expenses and profit is shown in Figure 3.

Figure 3
Revenues, Expenses and Profit
All Alaska Production
 (billions of dollars)

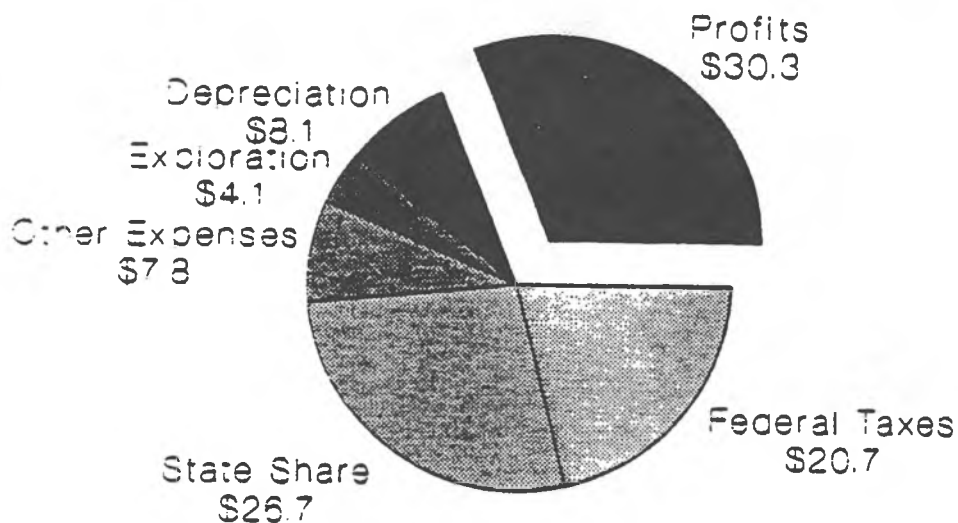


Table 7 shows the annual profits received from production activities in Alaska from 1969 through 1987.

Table 7
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1983 - 1987:					
	<i>1987</i>	<i>1986</i>	<i>1985</i>	<i>1984</i>	<i>1983</i>
Production Revenue	\$8,046	\$5,367	\$11,735	\$11,592	\$11,564
Depreciation	1,394	1,418	1,123	866	779
Operating Expenses	940	653	679	678	500
Exploration Expenses	288	288	514	258	818
Overhead	139	133	173	106	111
Interest	192	183	183	148	150
Royalty	970	647	1,414	1,397	1,393
Severance Taxes	871	623	1,403	1,395	1,388
Property Taxes	197	192	188	172	159
State Income Taxes	92	37	182	189	174
Windfall Profit Taxes			39	235	475
Federal Income Taxes	<u>1,007</u>	<u>0</u>	<u>2,424</u>	<u>1,627</u>	<u>1,774</u>
Profit	<u>\$1,956</u>	<u>\$1,192</u>	<u>\$3,413</u>	<u>\$4,521</u>	<u>\$3,841</u>
Profit per barrel:	<u>\$3.18</u>	<u>\$2.01</u>	<u>\$5.83</u>	<u>\$8.15</u>	<u>\$6.97</u>
1978 - 1982:					
	<i>1982</i>	<i>1981</i>	<i>1980</i>	<i>1979</i>	<i>1978</i>
Revenue	\$12,785	\$14,484	\$9,961	\$6,321	\$2,254
Expenses:					
Depreciation	698	540	504	345	280
Operating Expenses	506	571	183	188	176
Exploration Expenses	647	419	176	174	274
Overhead	91	55	16	2	a
Interest	171	18	10	167	247
Royalty	1,641	1,745	1,198	762	272
Severance Taxes	1,536	1,291	923	622	195
Property Taxes	165	151	152	130	113
State Income Taxes	175	702	556	369	66
Windfall Profit Taxes	1,491	3,314	861		
Federal Income Taxes	<u>2,212</u>	<u>2,067</u>	<u>2,110</u>	<u>399</u>	<u>8</u>
Profit	<u>\$3,452</u>	<u>\$3,610</u>	<u>\$3,270</u>	<u>\$3,161</u>	<u>\$ 623</u>
Profit per barrel:	<u>\$6.33</u>	<u>\$6.96</u>	<u>\$6.21</u>	<u>\$6.97</u>	<u>\$1.56</u>

Table 7 (continued)
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1973 - 1977:

	1977	1976	1975	1974	1973
Revenue	\$ 1,054	\$ 380	\$ 396	\$ 372	\$ 377
Expenses:					
Depreciation	53	16	16	16	16
Operating Expenses	64	16	15	10	3
Exploration Expenses	25	25	25	25	25
Overhead	3	a	a	a	a
Interest	177	1	1	a	a
Royalty	131	46	48	45	45
Severance Taxes	76	28	27	15	15
Property Taxes	31	12	13	13	13
State Income Taxes	49	23	24	24	24
Federal Income Taxes	52	85	91	89	89
Profit	<u>\$ 394</u>	<u>\$ 133</u>	<u>\$ 142</u>	<u>\$ 140</u>	<u>\$ 140</u>
Profit per barrel:	<u>\$2.49</u>	<u>\$1.94</u>	<u>\$1.94</u>	<u>\$1.89</u>	<u>\$1.33</u>

1969 - 1972:

	1972	1971	1970	1969
Revenue	\$ 283	\$ 279	\$ 278	\$ 227
Expenses:				
Depreciation	16	16	17	14
Operating Expenses	3	2	1	1
Exploration Expenses	25	25	25	25
Overhead	a	a	a	a
Interest	a	a	a	a
Royalty	34	34	34	27
Severance Taxes	12	11	8	6
Property Taxes	13	10	14	13
State Income Taxes	17	17	17	13
Federal Income Taxes	63	63	64	50
Profit	<u>\$ 99</u>	<u>\$ 98</u>	<u>\$ 100</u>	<u>\$ 79</u>
Profit per barrel:	<u>\$1.23</u>	<u>\$1.22</u>	<u>\$1.17</u>	<u>\$1.04</u>

a. Less than \$1 million.

TAPS PROFIT

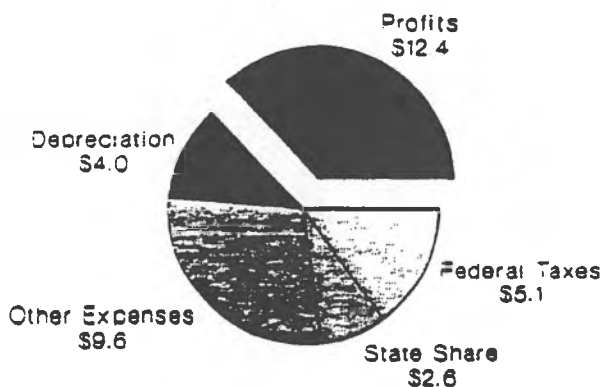
The Trans-Alaska Pipeline System (TAPS) is owned by the Prudhoe Bay producers in approximately the same proportion as their ownership interest in the Prudhoe Bay field. Profit from TAPS, therefore, accrues to the same producers. Table 8 shows the overall revenues, expenses and profit for TAPS from 1978 through 1987.²

Table 8
Total Estimated TAPS Profit
(billions of dollars)

Revenue	\$ 33.7
Expenses:	
Depreciation	4.0
Operating and Administrative	3.8
Interest	5.8
Property Taxes	1.7
State Income Taxes	.9
Federal Income Taxes	<u>5.1</u>
Profit	<u>\$12.4 Billion</u>
Profit per barrel: <u>\$2.41</u>	

The distribution of these items are shown in Figure 4.

Figure 4
TAPS Revenues, Costs and Profit
(billions of dollars)



²The one-half year of activity during 1977 when TAPS started does not have a significant effect on the results. Data from that year are unavailable.

A year-by-year comparison of TAPS profit is shown in Table 9.

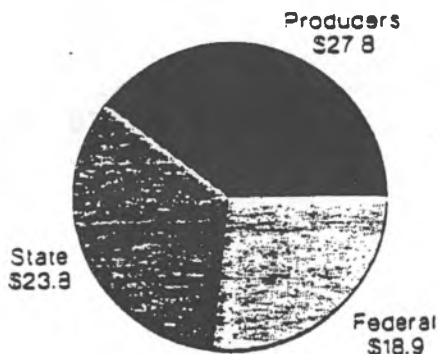
Table 9
Annual TAPS Profit
(millions of dollars)

1983 through 1987:					
	<i>1987</i>	<i>1986</i>	<i>1985</i>	<i>1984</i>	<i>1983</i>
Revenue	\$2,765	\$3,080	\$3,578	\$3,926	\$3,899
Expenses:					
Depreciation	299	310	309	431	475
Operating and Administrative	255	343	247	387	483
Interest	150	440	411	570	579
Property Taxes	147	164	168	171	165
State Income Taxes	57	55	73	71	66
Federal Income Taxes	<u>631</u>	<u>0</u>	<u>984</u>	<u>610</u>	<u>674</u>
Profit	<u>\$1.226</u>	<u>\$1.768</u>	<u>\$1.386</u>	<u>\$1.686</u>	<u>\$1.457</u>
Profit per barrel:	<u>\$2.08</u>	<u>\$3.07</u>	<u>\$2.44</u>	<u>\$3.17</u>	<u>\$2.77</u>
1978 to 1982:					
	<i>1982</i>	<i>1981</i>	<i>1980</i>	<i>1979</i>	<i>1978</i>
Revenue	\$3,896	\$3,605	\$3,554	\$2,963	\$2,394
Expenses:					
Depreciation	467	431	503	421	355
Operating and Administrative	498	474	435	330	381
Interest	648	681	720	771	846
Property Taxes	168	171	168	174	174
State Income Taxes	63	203	162	119	60
Federal Income Taxes	<u>802</u>	<u>599</u>	<u>617</u>	<u>129</u>	<u>8</u>
Profit	<u>\$1.250</u>	<u>\$1.046</u>	<u>\$ 949</u>	<u>\$1.019</u>	<u>\$ 570</u>
Profit per barrel:	<u>\$2.42</u>	<u>\$2.15</u>	<u>\$1.95</u>	<u>\$2.49</u>	<u>\$1.64</u>

SHARES

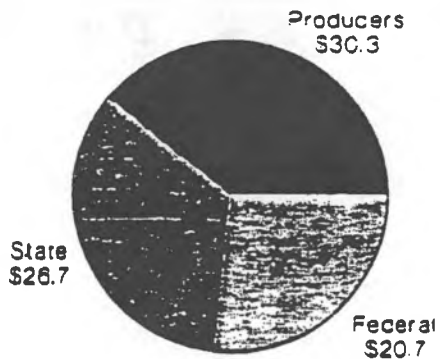
At the super-giant Prudhoe Bay field, producers earned \$27.8 billion. The State received \$23.8 billion from Prudhoe Bay and the Federal government received \$18.9 billion. This is shown visually in Figure 5. The nearby giant Kuparuk field added \$1.3 billion to producer profit, \$1.2 to the state and \$0.6 billion to the Federal government's revenues.

**Figure 5
Shares
Prudhoe Bay Production
(billions of dollars)**



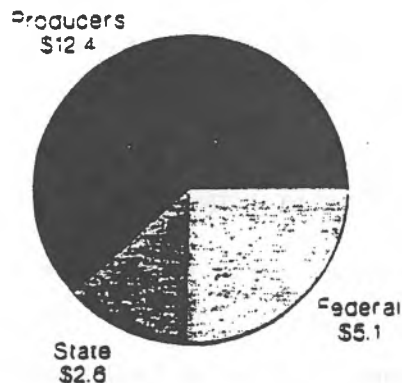
The sharing from all production in Alaska between 1969 and 1987 is shown in Figure 6, with \$30.3 billion to the producers, \$26.7 billion to the State and \$20.7 billion to the Federal government.

**Figure 6
Shares
All Alaska Production
(billions of dollars)**



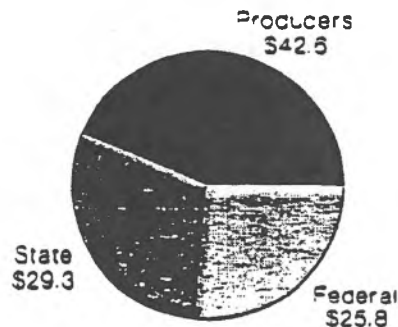
TAPS profit of \$12.4 billion went to the producers, \$2.6 billion went to the State through property and income taxes and \$5.1 billion went to the Federal government through income taxes. This distribution is shown in Figure 7.

Figure 7
TAPS Shares
(billions of dollars)



A summary of the distribution for all Alaska oil operations is shown in Figure 8. The \$42.6 billion in after-tax profit that accrued to the oil producers compares to \$29.3 billion in State of Alaska receipts from oil industry activities during this period. During the same period, Federal government receipts were \$25.8 billion from these activities. Figure 8 shows the relationship between industry profit and the state and federal receipts from oil industry revenues.

Figure 8
Shares
All Alaska Production and Transportation
(billions of dollars)



ADDITIONAL BENEFITS OF ANS OIL

ANS producers receive profits from Alaska oil outside of Alaska which provides an additional bonus beyond what it would cost if they had to purchase imported oil. An additional profit of approximately \$0.7 billion went to the producers through the operation of the U.S. Department of Energy crude oil entitlements program. Producers are believed to earn additional profit through the refining of ANS crude because, among other things, they have access to a secure source of crude oil. If they did not have the ANS crude, it would be necessary for them to acquire crude from foreign sources.

Others estimate that profits on tanker operations and trans-Panama shipment activities added between \$.25 and \$1.00 profit per barrel of ANS crude produced. These additional profits would have been received on the nearly 6 billion barrels of ANS production. These added profits are not included in the \$42.6 billion of total oil industry profit in Alaska covered in this report.

INVESTMENTS MADE ON THE ALASKA NORTH SLOPE

Figure 9 shows the relative amounts of money invested in projects to produce ANS crude. The greatest investment was \$9.4 billion in TAPS. The total investment to date in Prudhoe Bay was \$8.7 billion. This includes the waterflood project and the miscible gas injection project as well as infield drilling. The investment in Kuparuk was \$4.3 billion which includes amounts for the newly installed waterflood project that had not been in operation during the period of this study. Milne Point cost \$575 million. Endicott and Lisburne each cost approximately one billion dollars. As of the end of 1987, Milne Point had been shut in, while Endicott and Lisburne had just begun operations too recently to have a significant impact on the revenue numbers reported here. The investments made in Cook Inlet during this period were not significant relative to the ANS investments during this period.

Figure 9
ANS Investments
(billions of dollars)

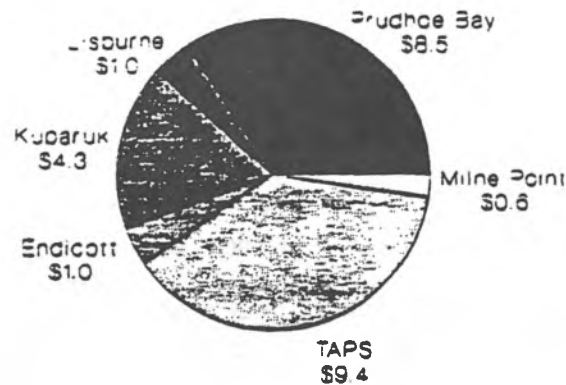


Table 10 shows the timing of the investments in Prudhoe Bay and other ANS projects together with an estimate of the timing of the investment in TAPS. These investment timings are based on information from the producers and may not be exact.

Table 10
ANS Investments
(millions of dollars)

<i>Year</i>	<i>Project</i>	<i>Amount</i>
1987	Prudhoe gas	\$ 720
1987	Kuperuk waterflood	900
1987	Endicott	1,000
1986	Lisburne	1,000
1985	Prudhoe gas plant	720
1984	Milne Point	570
1983	Prudhoe waterflood	2,000
1981	Kuperuk	3,400
1981	Prudhoe drilling	1,100
1980	Prudhoe drilling	250
1979	Prudhoe drilling	250
1977	Prudhoe*	1,850
1977	TAPS*	4,700
1976	Prudhoe*	1,850
1976	TAPS*	4,700
Total		\$ 25,015

*These amounts were spent over the period 1969 through 1977, with the majority of the funds spent later in the construction phase of the project.

Cash flows can be related to these investments to compute a rate of return on the investment in Alaska. Assuming the entire investment was made with equity funds, cash flows are deemed equal to profit plus depreciation and interest. A schedule of these "all-equity" cash flows is shown in Table 11.

Table 11
All-Equity Cash Flows
(millions of dollars)

Year	Investment	—Cash Flows—		Net Cash Flow
		Production	TAPS	
1987	2,620	3,542	1,675	2,597
1986	1,000	2,793	2,518	4,311
1985	720	4,719	2,106	6,105
1984	570	5,512	2,687	7,629
1983	2,000	4,770	2,511	5,281
1982	0	4,321	2,365	6,686
1981	4,500	4,168	2,158	1,826
1980	250	3,764	2,172	5,686
1979	250	3,673	2,211	5,634
1978	0	1,151	1,771	2,922
1977	6,550	655	0	-5,895
1976	6,550	0	0	-6,550

The equivalent rate of return earned on this stream of cash flows after tax is 29.7%.

As it happened, a substantial portion of the investment was financed with borrowed monies. The 1978 Sohio annual report to shareholders indicated that 75% of the company's funds were from debt. In this case, the investments in 1976 and 1977 as shown in Table 11 would be \$1,638 net each year. This is 25% of the investment outflows in those years. The remainder would have been financed with debt. Interest expense would be incurred on this debt and the debt would have to be repaid. The cash flow data in Table 12 is the profit plus depreciation. These cash flows include a deduction for interest expense. Assuming that all of the cash flows were used to pay of the debt as quickly as possible, the loan repayment would have consumed all of the cash flows in 1978

through 1979 and all but \$2,131 million in 1980. The net cash flows in each year are shown in column 4 of Table 12.³

Table 12
Cash Flows with 75% Borrowing
(millions of dollars)

	<i>Investment</i>	<i>—Cash Flow—</i>		<i>Net Cash Flow</i>
		<i>Production</i>	<i>TAPS</i>	
1987	2,620	3,350	1,525	2,255
1986	1,000	2,610	2,078	3,688
1985	720	4,536	1,695	5,511
1984	570	5,364	2,117	6,911
1983	2,000	4,620	1,932	4,552
1982	0	4,150	1,717	5,867
1981	4,500	4,150	1,477	1,127
1980	250	3,754	1,452	2,131
1979	250	3,506	1,440	0
1978	0	903	925	0
1977	6,550	478	0	-1,160
1976	6,550	0	0	-1,637

The rate of return implied from the stream of cash flows shown in Table 12 is 43.7%.

REINVESTMENT OF ALASKA PROFIT

A question of importance to Alaska is what happens to the profit earned from oil activities in Alaska. It has been necessary for the industry to make certain investments to maximize production from the Prudhoe Bay field. Initial investments are shown in 1976 and 1977 in Table 10. Reinvestments are shown in Table 10 for the years 1978 through 1987. In addition, the industry has reinvested through exploration.

Reinvestments shown in Table 10 are added to exploration expenses to obtain total reinvestments for the period 1978 through 1987. These reinvestments are shown in the first column of Table 13. For the years 1978

³Loan repayments took place over a longer time period, but it is not feasible within this project to determine actual repayment dates for ANS investment-related debt. This model assumes earlier repayment, but also includes the later interest costs reported by the producers. The net effect of this is to understate the rate of return.

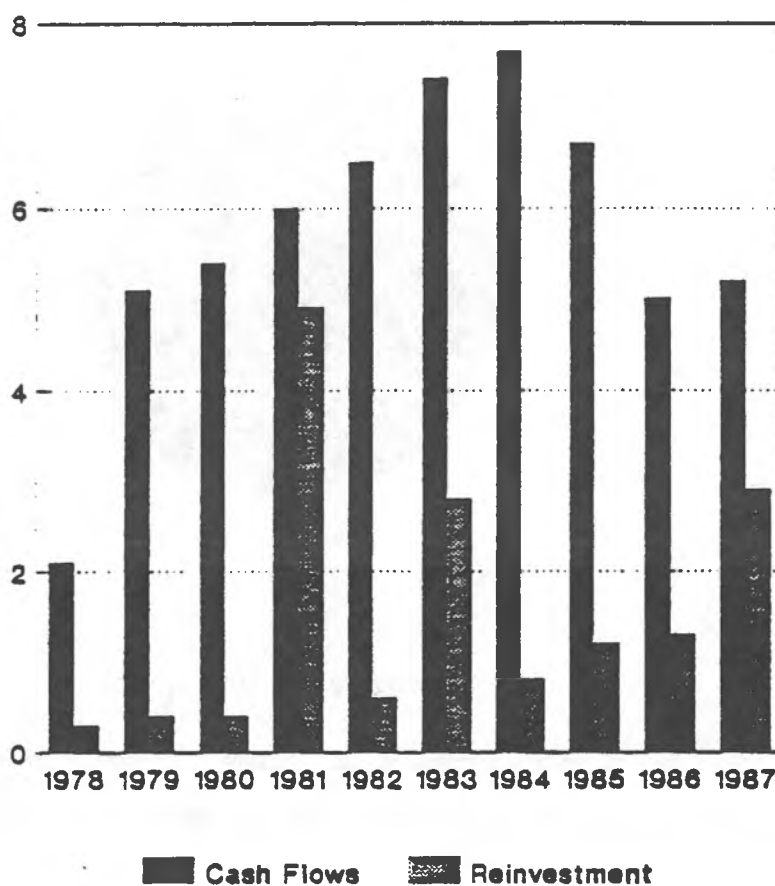
through 1987, these reinvestments are compared to cash flows received from Alaska oil operations. These cash flows are equal to profit plus depreciation and exploration expenses. They are shown as the third and fourth columns in Table 13. Each year's ratio of reinvestment to cash flows is shown in the last column of Table 13.

Table 13
Reinvestment and Reinvestment Flows
(millions of dollars)

<i>Year</i>	<i>Re-</i> <i>investment</i>	<i>Production</i>	<i>---Cash Flows---</i> <i>TAPS</i>	<i>Total</i>	<i>Reinvestment</i> <i>Ratio</i>
1987	2,908	3,638	1,525	5,163	56.32%
1986	1,288	2,898	2,078	4,976	25.88%
1985	1,234	5,050	1,695	6,745	18.30%
1984	828	5,622	2,117	7,739	10.70%
1983	2,818	5,438	1,932	7,370	38.24%
1982	647	4,797	1,717	6,514	9.93%
1981	4,919	4,569	1,477	6,046	81.36%
1980	426	3,930	1,452	5,382	7.92%
1979	424	3,680	1,440	5,120	8.28%
1978	274	1,177	925	2,102	13.04%

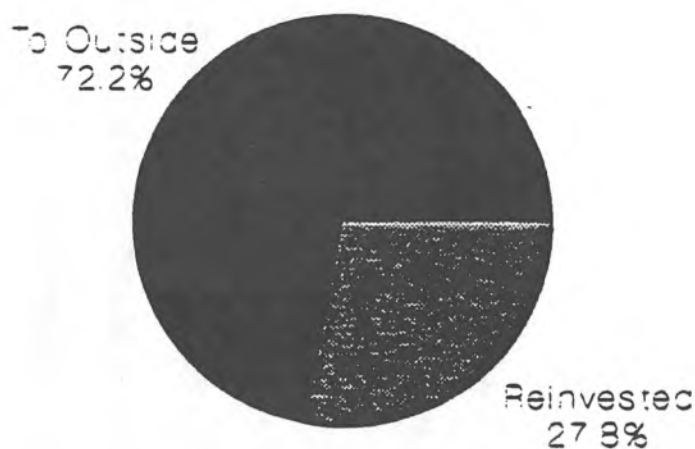
Table 13 indicates that 27.8% of the cash flows from oil and gas industry activities in Alaska was reinvested in Alaska. The reinvestment is shown graphically in Figure 10.

Figure 10
Reinvestment in Alaska by Years
 (billions of dollars)



The relationship between the percentage of funds reinvested in Alaska oil projects and those which flow outside is shown in Figure 11.

Figure 11
Overall Reinvestment of Oil Industry Flows
(percentage)



HOURLY PROFIT RATE

Looking at these profits as an hourly earnings number may bring the amounts into better perspective. After-tax profits have been earned by the producers at the rate of \$463,144 per hour, twenty-four hours per day for each day of the first ten and one-half years of ANS production.

SENSITIVITY OF ESTIMATES

Where possible, the different assumptions used to develop these profit estimates were studied in more detail to see how sensitive the profit estimates were to the different assumptions. When in doubt, a conservative approach was taken. A total of \$7.5 billion in potential profit increases related to assumptions

that were resolved in favor of conservatism was ignored. By contrast, a total of \$.6 billion in potential profit decreases related to assumptions were also ignored.

After considering the impact of all potential adjustments due to the assumptions used in the report, the range of profit estimates runs from a minimum of \$41 billion to a maximum of \$47 billion. The \$42.6 billion reported here is at the low end of this range.

References

- Alaska Department of Natural Resources, *Historical and Projected Oil and Gas Consumption* (January 1988)
- Alaska Department of Revenue, *Revenue Sources: Quarterly Updates* (1987 and 1988)
- Alaska Division of Policy, Office of the Governor, *The ELF: A Policy Perspective* (April 1988)
- Alaska Oil and Gas Conservation Commission, *Statistical Reports*, 1974 to 1981.
- Alaska Oil and Gas Conservation Commission, *Production Statistics* computer printouts. (1985 through 1987)
- Alaska House Research Agency, *The Effects of State Income Tax Policy on the Development of Marginal Oil Fields*, House Research Agency Report 86-c (1986)
- American Petroleum Institute, *Joint Association Survey* (1984)
- Arco Pipeline Company, *FERC Annual Reports*, 1981 to 1985.
- Atlantic Richfield Company (ARCO), *Annual Reports and Annual Reports on Form 10-K*, 1979 through 1987.
- BP America, *Annual Report* (1987)
- Barclays de Zoete Wedd, *British Petroleum in Alaska* (September 1988)
- Cost Accounting Standards Board, *Cost Accounting Standards* (1980)
- Deakin, Edward B., "Profitability Estimates of Prudhoe Bay Oil Field Using Financial Statement Data", *Oil and Gas Tax Quarterly* (Fall 1988)
- Deakin, Edward B. "Income and Investment Flows from Alaska Oil and Gas Producing Activities", *Report of the Joint Committee on Taxation*, Alaska Legislature (1987)
- Deakin, Edward B. and Michael W. Maher, *Cost Accounting, 2nd ed.* (Homewood, Illinois: R. D. Irwin), 1987.
- DeGolyer and MacNaughton, *Twentieth Century Petroleum Statistics* (1988)
- Exxon Corporation, *Annual Reports and Form 10-K's*, 1979 to 1986.
- Exxon Pipeline Company, *FERC Annual Reports*, 1981 to 1985.
- Financial Accounting Standards Board, *Statements of Financial Accounting Concepts 1 - 5*, (1987)
- First Boston Equity Research, *Alaska's Prudhoe Bay Field: An Oil Price/Cash Flow Sensitivity Analysis* (1986)
- International Petroleum Encyclopedia* (1983 - 1985 and 1987)
- International Petroleum Finance*, "Alaska's Oil Promise Remains Strong" (1988)
- Petroleum Intelligence Weekly* "Alaska Oil Profits Staying Buoyant Amid Volatile Prices" (February 1988)
- Salomon Brothers Inc. "Atlantic Richfield Company: Restructured and Resourceful" (1987 and 1988)

References
(continued)

Settlement Agreement Between The State of Alaska and Arco Pipe Line Company et al. with Respect to the Trans Alaska Pipeline System (June 1985)

Sohio (Standard Oil Co. of Ohio), *Annual Reports*, 1973 to 1986.

Sohio Alaska Pipeline Company, *FERC Annual Reports*, 1981 through 1987.

U.S. Bureau of Census, *Current Industrial Surveys: Oil and Gas* (1978 to 1982)

U.S. Energy Statistics Sourcebook 1988 (Tulsa: Pennwell Books) 1989.

U.S. Internal Revenue Service, *Statistics of Income Bulletins*, (1981 to 1986)

Oil Industry Profitability in Alaska

1969 through 1987

TECHNICAL DISCUSSION

Confidential Pursuant to
APUC Order P-97-4(22)

RTSXMB 519694

T-33000125

Oil Industry Profitability in Alaska 1969 through 1987

Index to Technical Discussion

Introduction	T-1
Approach to Measuring Alaska Oil Company Profit	T-1
I. Production Revenues	T-7
Production Estimates	T-7
Revenue Estimates	T-14
II. Production Expenses	T-24
Production Depreciation Estimates	T-24
Severance Taxes	T-30
Operating Expenses	T-33
Windfall Profit Taxes	T-38
Exploration Expenses	T-41
Overhead and Interest Expense	T-42
State Income Taxes	T-48
Federal Income Taxes	T-49
III. Production Profit	T-53
IV. TAPS Profit	T-64
V. Other Information	T-70
Downstream Profit	T-70
Profit Shares	T-71
Rate of Return	T-67
Reinvestment	T-75
Appendix A: Sample Sohio Alaska Disclosure	T-77
Appendix B: Barclay's Prudhoe Bay Model	T-78
Appendix C: Salomon Brother's ANS Model	T-79
Appendix D: Alaska Oil Development Time Line	T-80
Appendix E: Total ANS Production and TAPS Profits: 1977 through 1987	T-81

Technical Discussion

The profit estimates reported in this report were developed from publicly available information about oil industry activities in Alaska. Although a substantial amount of information exists about oil industry activities in Alaska, a complete picture of profit from Alaska activities is not published in any known reference. Assembling a report on oil industry profit requires gathering information from a number of different sources, piecing together an overall picture of profit and cross-checking the estimate obtained in this manner with other data sources. In the end, the profit estimate should be quite close to the actual results.

Throughout this report the terms "approximate" and "estimate" appear quite frequently. These terms are necessary because public data do not exist which would enable one to compute Alaska profit precisely. The approach taken here, when there are questions about amounts, is to take the conservative approach. The profit reported then will represent the low end of the range. This section of the report provides details on how the pieces of the puzzle were assembled and how the resulting profit estimates were cross checked. After all of this, some questions still remain. The effect of these remaining questions is covered in Section III of this technical discussion.

APPROACH TO MEASURING ALASKA OIL COMPANY PROFIT

In its most fundamental form, profit is the amount that is left over from revenues after paying all expenses including income taxes and an allowance for the cost of the initial investment. In accounting terms, estimation of profit becomes more complex because accountants must relate revenues to expenses that occur in different times. Accounting profits therefore are based on an

analysis of transactions that took place in the past with appropriate adjustments to determine the profit attributable to a specific period of time. In this report, profit from Alaska oil industry activities are estimated over the period 1969 through 1987.¹

Alaska oil producers earn profit from the production, transportation and sale of crude oil. The primary sources of these profits are production from Prudhoe Bay field on the Alaska North Slope (ANS) and TAPS.

A company engaged in Alaska oil activities can estimate its own profit rather readily by extracting transaction data from its own books and by making appropriate adjustments. To make such an estimate from the outside is much more complex because a significant portion of company data is kept private. Hence, it is necessary to identify that information which is public and piece together a picture of the profitability of Alaska oil operations. This task requires obtaining as much information as possible and then making assumptions about the missing data and, where possible, cross-checking the results with other public data sources. This is the process followed to develop the profit estimates reported here.

For example, Standard Oil Company of Ohio (formerly Sohio, now BP America) includes a section in its corporate annual report that states its profit from Alaska oil production operations. (See Appendix A for an example of this disclosure.) If every other producer obtained the same revenues per barrel of crude oil and incurred the same costs to produce that oil, one could project from the Sohio data to all Alaska production. However, this approach cannot be used because it is widely known that Sohio sells most of its ANS crude on the U.S. Gulf Coast whereas other producers sell their crude oil on the U.S. West Coast.

¹See Financial Accounting Standards Board, *Statement of Financial Accounting Concepts No. 3*, Pars. 12 and 56 - 62 for a comprehensive discussion of profit concepts.

Prices in the two markets differ. According to Barclay's de Zoete Wedd (1988), U.S. West Coast prices are about \$1 lower than the Gulf Coast, but it costs about \$2.45 more to ship a barrel of crude oil to the Gulf Coast. To obtain revenues for all producers, it is necessary to adjust Sohio revenues by taking account of the differences in crude oil values. This is one of the many adjustments necessary to obtain an estimate of profit.

The more assumptions that need to be made, the more questions that will arise about the profit number that is obtained. However, there are alternate sources of information that can be used to compare a significant portion of the data used to compute profit. To the extent that these alternate sources are consistent, the computed profits will be more reliable. The most important item in the profit equation is revenue. Fortunately, estimates of producers can be checked against Alaska severance tax collections. For most of the period covered by this report, the Alaska severance tax is stated as 15% of the value of producers' production, subject to certain adjustments. This implies that for production subject to the 15% rate, an amount equal to 15% of production revenue should approximate the reported severance tax collections by the State of Alaska. Similar comparisons can be made for production subject to other severance tax rates.

In addition, the estimate included in this report is not the only estimate of oil industry profit in Alaska. Financial analysts and others have, from time to time, estimated profit from Alaska oil industry activities. (See Appendices B and C for examples.) The numbers reported here have been checked, to the extent possible, with other data sources.

Not all of the numbers can be checked and many of the alternate information sources use different bases for reporting their data. The last part of section III of

this report discusses the effects that substantial questions raised by the estimation process are likely to have on the total estimated profit. As noted in this report, most of the effects are quite small. This is an unavoidable problem. Indeed, it is very likely that producers are unable to estimate their own profits down to the last cent because of the assumptions that they make in developing their profit numbers. The point is that the estimate developed here is, on balance, consistent with other estimates of profits earned in Alaska. Indeed, the total effect of questions about alternate treatments is that the profit reported here is on the conservative side. One may perhaps argue that total profit is \$2 billion higher or lower than this estimate, but such a debate should not detract from the validity of the overall picture presented here.

The first part of this report develops estimated revenues from production activities, essentially the gross receipts from operations. This report focuses on the revenues that accrue to the producers, net of royalty. This is defined as "working interest revenue." To calculate working interest revenue, it is necessary to know production and the value of each barrel of production. Those matters are discussed in Section I under "Production Revenues".

Section II covers the expenses that must be deducted from revenues to obtain profit for this project. These expenses include depreciation, severance taxes, operating expenses, windfall profit taxes, exploration expenses, overhead and interest. Each of these items is discussed in turn. Both the State of Alaska and the U.S. government levy taxes on income as defined in their laws. These are expenses for accounting purposes and are also presented in Section II. Royalties are eliminated from revenues reported by oil and gas producers. In Section III, royalties are included as a separate line item to determine both the working interest (producers') revenues and total revenues.

The third section of the report gives the detailed statements of profit for Prudhoe Bay, Kuparuk and all Alaska production. This section also includes a discussion of the sensitivity of the profit estimates to cost estimates, missing data, various allocations, and other factors on the profit estimates.

The fourth section of the report shows the profit earned from TAPS. Here it is reasonable to rely extensively on Sohio Pipeline Company's disclosures. Other data sources generally confirm the Sohio Pipeline information.

Each part of this technical discussion is designed to provide further detail about the way the data presented in the report was developed. To the extent possible, the report follows accounting practices and conventions that enable one to obtain a reasonable estimate of the profitability of Alaska's oil industry activities. The resulting estimates give an accurate, although not exact, picture of the profitability of Alaska's oil industry operations.

Profit has been estimated for Prudhoe Bay, Kuparuk, all Alaska production and TAPS. After making all of the calculations and cross-checking available data, total oil industry profit in Alaska is estimated as \$42.6 billion. This includes \$27.8 billion from Prudhoe Bay, \$1.3 billion from Kuparuk and \$12.4 billion from TAPS. An additional \$1.1 billion was earned elsewhere in Alaska.

After looking at the effects of all of the estimates made on reported profit, a range within which the actual number is likely to fall can be developed. The low end of this range is \$41 billion and the high end is \$47 billion. The estimated profit of \$42.6 billion reported here is in the low end of this conservative estimated range.

Finally, reported profit is based on public information which was available at the time this report was written. It is entirely possible that data not available

T-6

could affect the analysis. Any such data would be welcomed to advance the goal of obtaining a more precise estimate of Alaska oil industry profit.

I. PRODUCTION REVENUES

PRODUCTION ESTIMATES

Production estimates for crude oil and natural gas were obtained from different data sources and compared. Since the foundation of reported profit depends on production estimates, it is important to note how the estimates compare. Moreover, each company's reported accounting data are based on its production estimates. Thus, the production data are needed for making certain computations from company reports. The estimates for crude oil are discussed first in this section, followed by the estimates for natural gas.

Crude Oil. Production estimates were obtained from the corporate annual reports of Arco, Sohio and BP America, the Alaska Oil and Gas Conservation Commission Statistical Series, DeGolyer and MacNaughton's *20th Century Petroleum Statistics* (1987) and the *International Petroleum Encyclopedia*, as well as from the *U.S. Energy Statistics Sourcebook* (1988). As shown below, the estimates provided by each of these sources differ with respect to the time periods covered, the level of detail and the volumes of production.

The producers' corporate annual reports present production information in terms of barrels per day of production. The data as reported by each company are shown in Table I-1.

Arco presented separate information on the production from Prudhoe Bay, Kuparuk and Lisburne for the years 1980 through 1987. From 1978 on, Sohio/BP presented data for all of its Alaska operations. Prior to 1982, virtually all of Sohio/BP's production was from the Prudhoe Bay field. These data facilitated obtaining production estimates for each of those fields.

Table I-1
Company Net Production Data
 (000 barrels per day)

Year	-----Arco Reports-----			Sohio/BP
	Prudhoe	Kuparuk	Lisburne	
1987	324.9	122.0	15.0	827.2*
1986	306.9	109.9	4.1	706.4#
1985	304.9	94.9	8.5	699.7
1984	326.1	71.7	8.9	617.9
1983	336.4	69.9	10.0	594.8
1982	292.4	61.8	na	676.6
1981	275.5	2.1	na	698.2
1980	274.7			696.4
1979	248.6**			590.8
1978	213.3**			506.8
1977	213.3**			143.8
1976	78.4**			
1975	27.9**			

* BP America data.

Sohio data. BP America reported 781.4 thousand barrels per day.

** Arco's total Alaska production.

The data reported in Table I-1 were converted to an annual number by multiplying the daily figures by 365. The company statistics were then divided by the company's proportionate share in production to arrive at an estimate of total production based on each company estimate. Adjustments were made for the 1982 redetermination of each company's Prudhoe Bay share of production. The estimates of total Prudhoe Bay production based on Arco's and Sohio/BP's corporate disclosures are in the first two columns of Table I-2, below. The estimates of total Kuparuk production based on Arco's corporate disclosures are in the first column of Table I-3, below. The corporate disclosures give the company's working interest production (net of royalty).

The Alaska Oil and Gas Conservation Commission provides gross production by field for all years covered by this study. The *International Petroleum Encyclopedia* reports gross production from major fields by year. However, the *Encyclopedia* is not complete. In certain years it does not show all fields.

The DeGolyer and MacNaughton statistics are based on the U.S. Department of Energy reports and show gross production from Alaska. They do not show production from specific fields.

The *U.S. Energy Statistics Sourcebook* data show total ANS production for 1981 through 1987 and total Alaska production for prior years. An assumed 1/8 royalty interest was deducted from this number to arrive at an estimate of ANS working interest production. Production from Kuparuk and Lisburne (based on Arco's disclosures) were deducted to arrive at an estimate of Prudhoe Bay production. These data are in Column 3 of Table I-2.

The estimates presented under each method differed. To test the different estimates for reasonableness, TAPS and Kuparuk pipeline throughputs were analyzed. This analysis is based on the assumption that all of Kuparuk production (including royalty oil) should equal the Kuparuk pipeline throughput. TAPS throughput should be comprised of Kuparuk, Lisburne, and Prudhoe Bay crude, including royalty oil. Deducting Kuparuk, Lisburne and Prudhoe Bay royalty oil should give the working interest production from Prudhoe Bay.

Annual total TAPS throughput for 1982 through 1987 was obtained from the Arco annual report. Similar data for 1980 to 1981 were obtained from the Sohio report. Royalty interests as well as Lisburne and Kuparuk production were deducted from total TAPS throughput to obtain an estimate of Prudhoe Bay production. The results of this analysis are shown in Column 5 of Table I-2.

In addition to these estimates, data on total production from Prudhoe Bay, including royalty, were presented in the *International Petroleum Encyclopedia*. These data were available for 1983, 1984, 1985, and 1987. Royalty of 1/8 was deducted from gross production to obtain another estimate of Prudhoe Bay working interest production for comparison purposes.

The sources that provided reasonably complete data series included Arco, Sohio/BP, the *U.S. Energy Statistics Sourcebook*, the Alaska Oil and Gas Conservation Commission statistics and the analysis of pipeline throughput. The estimated working interest production from Prudhoe Bay based on each of these different estimates is shown in Table I-2. After reviewing the data and the different levels of complexity required for each alternate estimate, it appears that the Alaska Oil and Gas Conservation Commission (AOGCC) statistics provided a reasonable, conservative and consistent data series over the period covered by this report.

Table I-2
Annual Production Estimates: Prudhoe Bay
Net of Royalty
 (000,000 barrels per year)

<i>Year</i>	<i>Arco</i>	<i>Sohio/BP</i>	<i>U.S. Energy Data Sourcebook</i>	<i>AOGCC Statistics</i>	<i>Pipeline Throughput Analysis</i>
1987	544.5	592.0	507.3	500.8	520.9
1986	500.1	508.8	493.6	494.5	493.8
1985	496.8	503.9	497.8	498.5	497.3
1984	531.4	467.5	492.1	491.9	489.6
1983	547.4	458.6	487.3	490.8	486.1
1982	492.7	490.0	489.2	489.2	488.4
1981	493.4	480.8	486.7	485.8	495.0
1980	527.7	479.6	517.7	486.0	479.1
1979	na	406.9	447.4	409.9	na
1978	na	349.0	392.5	348.0	na
1977	na	99.1	148.1	100.9	na

For 1977 through 1986, production estimates used for computing Prudhoe Bay profit are based on the AOGCC statistics shown in Table I-2. The 1987 estimate used the AOGCC estimate for Prudhoe Bay plus Arco's estimate for Lisburne. The production number chosen was neither the highest nor the lowest for all years. It is generally believed that the AOGCC estimates are reliable and acceptable estimates of field production.

Kuparuk production estimates are based on 7/8 of Kuparuk pipeline throughput as reported by Arco. The 7/8 number reflects the net working interest

production. The *International Petroleum Encyclopedia* also reported estimated production from Kuparuk. The *International Petroleum Encyclopedia* data were adjusted to reflect a 1/8 royalty interest. The AOGCC reported Kuparuk production was adjusted to reflect a 1/8 royalty interest also. These different annual working interest production estimates for Kuparuk are reproduced in Table I-3.

Table I-3
Annual Production Estimates: Kuparuk
Net of Royalty
 (000,000 barrels per year)

<i>Year</i>	<i>Arco</i>	<i>International Petroleum Encyclopedia</i>	<i>AOGCC Statistics</i>
1987	90.4	87.1	89.6
1986	87.2	na	82.2
1985	70.3	69.6	69.7
1984	40.2	32.6	40.4
1983	38.3	34.0	34.9
1982	28.4	na	28.6
1981	na	na	.1

The Arco data are slightly higher for most of the years of Kuparuk production. Since the differences are minor, the Arco production data were used for Kuparuk. The very small production from Milne Point and Endicott would be included with Kuparuk. However, the amounts are too small to affect the analysis.

Lisburne production was reported by Arco at 14.4 million barrels in 1987. The *International Petroleum Encyclopedia* and the AOGCC reported this production at 14.3 million barrels in 1987. This amount has been included with Prudhoe Bay production in subsequent analysis.

For 1981 through 1987 and for years prior to 1978, other Alaska production was reported separately in the *U.S. Energy Statistics Sourcebook*. These data were used for comparison for those periods. For 1978 through 1980, other Alaska production was estimated as the difference between total Alaska production as reported in the *U.S. Energy Statistics Sourcebook* and ANS

production as computed in the two tables above. The results gave significantly higher estimates of other Alaska production during those three years. It was not possible to ascertain the reasons for the difference between these data and the AOGCC data. The two series of working interest production estimates for non-ANS production reproduced in Table I-4.

Table I-4
Non-ANS Production Estimates
Net of Royalty
 (millions of barrels)

<i>Year</i>	<i>AOGCC Statistics</i>	<i>U.S. Energy Statistics Sourcebook</i>
1987	14.3	14.1
1986	15.4	15.4
1985	14.8	14.8
1984	19.3	19.2
1983	21.7	21.7
1982	24.0	24.0
1981	27.1	27.2
1980	31.7	98.1
1979	37.5	91.4
1978	43.8	87.1
1977	49.1	61.4
1976	58.6	55.5
1975	63.0	61.1
1974	63.2	61.8
1973	64.0	63.3
1972	64.4	63.8
1971	69.0	70.0
1970	73.2	73.2
1969	65.0	64.7

The Alaska Oil and Gas Commission statistics were used for purposes of non-ANS production in this report. The differences between AOGCC and an approach based on the Energy Statistics Sourcebook appears significant only in the years 1977 through 1980. During that period, the AOGCC data appear more reliable because the significant increase in production indicated for 1978 - 1980 by the *U.S. Energy Statistics Sourcebook* cannot be confirmed from other sources. It appears that this increase is a statistical fluke. In other years the two

data series track one another closely. It is unlikely that the differences in other years would have any substantial effect on the results.

Natural Gas. Estimation of natural gas production was simplified because there were fewer data sources. BP/Sohio provided information about gas production in their annual reports. All of Sohio's gas production was on the North Slope, and most of that was produced from Prudhoe Bay for use in production operations. Estimates of natural gas production in column 1 of Table I-5 are based on these data. The *U.S. Energy Statistics Sourcebook* provided data on total Alaska natural gas production. This data series is gross of royalty. Adjusting the *U.S. Energy Statistics Sourcebook* data for a 1/8 royalty and deducting the Sohio-based estimate of ANS production gives an estimate of ANS natural gas working interest production and other Alaska natural gas working interest production. The non-ANS production data computed by this method are reported in column 3 of Table I-5. These estimates were compared with AOGCC data and with data reported by the U.S. Department of Energy. The differences were not significant.

Table I-5
Natural Gas Production Estimates
Net of Royalty
 (billions of cubic feet)

<i>Year</i>	<i>ANS per BP/Sohio</i>	<i>All Alaska per Sourcebook</i>	<i>Non-ANS Estimate</i>
1987	80.1	314.8	234.6
1986	70.4	266.7	196.4
1985	55.5	281.2	225.6
1984	41.8	253.0	211.2
1983	39.4	242.1	202.7
1982	35.8	231.3	195.5
1981	33.2	212.2	179.0
1980	48.5	201.8	153.2
1979	25.6	193.2	167.5
1978	20.5	177.7	157.2
1977	8.0	164.4	156.4
1976			145.3
1975			140.2
1974			112.8
1973			114.6
1972			110.0
1971			106.4
1970			97.6
1969			44.5

REVENUE ESTIMATES

Production data multiplied by the price per unit of production gives gross revenues. The question is how to obtain an accurate estimate of the price per barrel of ANS crude oil given that the oil is disposed of at different prices.

There are several estimates of ANS per barrel revenue which must be considered when preparing a total revenue estimate. The approach used here was based primarily on the weighted average of the reported per barrel prices given in the producers' corporate annual reports. Adjustment was made to reflect the transportation and quality differences between Kuparuk and Prudhoe Bay crude. These adjustments were based on information provided by Salomon Brothers and Barclay's.

The first set of data used were the reported per barrel prices for crude oil obtained from the annual reports of Sohio and Arco as well as the *U.S. Energy*

Statistics Sourcebook. These data are presented in columns 1 through 3 respectively of Table I-6. In 1988, Barclay's produced a report on BP which, among other things, detailed revenues at Pump Station 1 for 1985 through 1987. This information is included in column 4 of Table I-6 for comparison.

Estimates given in Table I-6 are based on overall production. It is necessary to disaggregate the data for Prudhoe Bay and for Kuparuk. Given that Arco reported production for both fields, and that its per barrel revenue is, effectively, a weighted average of the prices from these two fields, it is possible to disaggregate the prices if the difference between the two prices is known. The difference between the Prudhoe Bay price and the Kuparuk price would be due to the Kuparuk pipeline tariff and a quality differential between the two fields.

Table I-6
Per Barrel ANS Revenue Data
(Pump Station #1)

<i>Year</i>	<i>Sohio</i>	<i>Arco</i>	<i>Sourcebook</i>	<i>Barclay's</i>
1987		\$ 10.95	\$ 10.84	\$ 10.74
1986	\$ 7.38	6.43	6.45	6.76
1985	16.92	16.81	16.98	17.83
1984	17.78	17.11	17.91	
1983	17.73	17.31	17.69	
1982	19.97	19.08	19.92	
1981	23.86	22.65	23.23	
1980	16.79	16.95	16.87	
1979	10.72	na	10.57	
1978	4.56	na	5.21	
1977			5.84	
1976			5.02	
1975			4.92	
1974			3.62	
1973			3.23	
1972			3.17	
1971			3.01	
1970			2.90	
1969			na	

According to Barclay's, the Kuparuk pipeline tariff is \$1.00 per barrel. Barclay's also estimated that the quality differential is \$.50. For the years 1982 and 1983, these estimates are consistent with other sources. Therefore, the

Kuparuk price should be \$1.50 per barrel less than the Prudhoe Bay price for 1982 and 1983. In 1984, the new Kuparuk pipeline was brought on stream and a new pipeline tariff established. *Petroleum Intelligence Weekly* (February 1988) and other sources indicate that the price difference between Prudhoe Bay and Kuparuk for 1982 and 1983 should equal \$.95 per barrel. In later years the difference declines. The \$.95 per barrel differential together with the average per barrel ANS price data were used to construct estimates of the price of crude oil for each field.

The formula for generating these estimates is developed as follows. For 1984 through 1987, Arco's average per barrel price:

$$\frac{P_{\text{Kuparuk}} \times (X - \$0.95) + P_{\text{Prudhoe}} \times X}{\text{Total Production}}$$

Where P = Production for each field and
X = Price for Prudhoe Bay

Using the formula for 1987, for example, gives the following price estimates:

$$\begin{aligned} \frac{122.0 \times (X - \$0.95) + 324.9 X}{446.9} &= 10.95 \\ X \text{ (Prudhoe Bay Price)} &= \underline{11.21} \\ X - \$0.95 \text{ (Kuparuk Price)} &= \underline{10.26} \end{aligned}$$

Similar estimates are obtained for each other year when Kuparuk was in production.

The amounts reported in Table I-6 and the field prices obtained from the calculations discussed above provide a starting point for determining the final estimate. The per barrel revenue amounts for Arco are widely believed to be greater than for Sohio because a greater portion of Arco's ANS crude is disposed of on the U.S. West Coast and, therefore, avoids the extra cost of the longer marine voyage and trans-Panama shipment.² The realizations for Exxon are

²See Barclay's de Zoete Wedd (1988), *Petroleum Intelligence Weekly* (Feb. 1, 1988) and Salomon Brothers (1987) for discussions of the differences in dispositions.

also believed to be somewhat greater than for Sohio because Exxon's dispositions occur almost exclusively on the U.S. West Coast. For these reasons, the per barrel data given in Table I-6 probably understate actual realizations. This belief is confirmed by reports by financial analysts such as Salomon Brothers and *Petroleum Intelligence Weekly* who use higher realization prices for Arco's ANS crude.

As a result of all these factors, it appeared that the revenue number needed to be adjusted for the greater proportion of dispositions on the West Coast by producers other than Arco and Sohio. Examination of price differentials for West Coast and Gulf Coast dispositions as well as cost differences suggests that, conservatively, crude oil disposed of on the West Coast should have a value that is approximately \$1 per barrel greater on the North Slope than crude oil disposed of elsewhere. Because public data are limited on the precise value of each North Slope company's crude oil, the revenue here is based on the assumption that Arco and Sohio's average disposition prices were as reported in their 10-K's and that other producers obtained an average of \$1 more per barrel for their crude. The difference is presumed due to Arco's netback method. The results are more consistent with outside analysts' observations and tie more closely to the State's reported severance tax collections. The Alaska Department of Revenue's report of revenue sources states that severance tax collections totalled \$10.2 billion over the period 1969 through 1987. The analysis in this report gives a total severance tax collection of \$10.4 billion. The amounts are within a 2.3% margin of error.

Estimates of total revenue for Prudhoe Bay were calculated by using a weighted average price for Prudhoe Bay crude oil. It was assumed that 51% of Prudhoe Bay crude was sold at the price reported by Sohio and 21% at the price calculated for Arco. The remaining 28% of Prudhoe Bay production was

assumed to have been sold at a price that was \$1 per barrel greater than that reported by Arco. This approximates the dispositions indicated in other information sources.³ Data were available to make these calculations for the years 1980 through 1986. In 1987, Sohio was no longer in existence as a separate entity. Its successor, BP America, did not report weighted average ANS crude prices. Dividing BP America's Alaska revenues by its ANS production gives a substitute estimate. For 1978 and 1979, data limitations required use of Sohio's prices. The 1977 average price was based on the *U.S. Energy Statistics Sourcebook* because other data were not available. Comparing all of the different estimates across time, it does not appear that using different base estimates will have a significant effect on the results.

An alternate method for computing Prudhoe Bay revenue is to take Sohio's price per barrel times total production. This should provide a lower overall estimate since Sohio's price realizations are expected to be lower due to their additional transportation costs.⁴ The weighted-average revenue estimate used in this report is 1.19% greater over the eleven-year production history. Given that Sohio's prices are expected to be lower, this lends further support to the assertion that the estimate used in this report is reasonably close, and probably somewhat conservative, relative to the actual revenue realized.⁵

³It may be possible to derive more accurate estimates of revenue. Examination of public and private data sources indicated in the list of references suggests that the resulting revenue estimates will be somewhat greater than those reported here.

⁴The per barrel prices reported in the 10-K are different from what one would expect given that Sohio's transportation costs downstream of Valdez are higher than the costs for Arco. The reasons for this discrepancy are unknown. The *Sourcebook* data series and the Barclay's data suggest that the per barrel numbers used here are not consistently the highest nor the lowest. Moreover, the different series are usually within a few cents per barrel of each other. At best, it appears that the data are approximately consistent. It is not possible to obtain an exact estimate of these revenues.

⁵Indeed, on a weighted average basis over the life of ANS production, an estimate using Sohio's price alone should be approximately 7% lower than actual realizations.

Kuparuk revenue was based on the calculated Kuparuk price per barrel times the production estimate for Kuparuk. The Kuparuk price was estimated by taking the weighted average Prudhoe Bay price and deducting \$0.95 per barrel for the years 1984 through 1987 and deducting \$1.50 per barrel for 1982 and 1983. The results conform to the prices reported in such other sources as *Petroleum Intelligence Weekly*, Salomon Brothers and Barclays de Zoete Wedd (1988).

For 1977 through 1987, price data for non-ANS crude was obtained from DeGolyer and MacNaughton's *20th Century Petroleum Statistics* (1988), which is derived from U.S. Department of Energy statistics. The DeGolyer and MacNaughton data report Tier I and Tier II prices, but do not indicate how much crude was sold under either price level. For lack of any available data, it has been assumed that 1/2 was Tier I and 1/2 was Tier II. Prior to 1977, the composite published Alaska prices are directly available from the *U.S. Energy Sourcebook*. Other Alaska crude oil revenue was based on the AOGCC production data times the prices obtained from DeGolyer and MacNaughton for 1978 through 1987 and from the *Sourcebook* for prior years. There does not appear to be a substantial difference between the estimates obtained under other methods not described here.

A summary of the estimated revenues realized for Prudhoe Bay (including Lisburne), Kuparuk (including Milne Point) and all other Alaska crude oil production is provided in Table I-7. These revenue data are net of royalty. In Section III, an adjustment is made to add royalty to these revenues and then to deduct it as an expense.

Table I-7
Crude Oil Revenue Data
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Other Alaska</i>	<i>Total</i>
1987	\$5,695	\$ 942	\$ 232	\$6,869
1986	3,729	575	191	4,495
1985	8,600	1,145	343	10,088
1984	8,842	685	468	9,995
1983	8,823	631	539	9,993
1982	9,842	528	674	11,044
1981	11,665		873	12,538
1980	8,304		284	8,568
1979	5,136		285	5,421
1978	1,587		291	1,878
1977	631		262	893
1976			294	294
1975			329	329
1974			311	311
1973			232	232
1972			208	208
1971			218	218
1970			221	221
1969			189	189

Natural Gas. Natural gas price estimates were available for Arco for the years 1983 through 1987. Sohio presented natural gas price data for 1977 through 1986. These numbers were used to estimate revenues from natural gas on the North Slope for the years when Prudhoe Bay was in production. The numbers are relatively close in amount. A weighted average was used for the years when both Arco and Sohio published these data. The assumption was that the Arco price was attributable to 76% of the production, the Sohio price was attributable to 24%, and the missing data are proportional to these numbers. Separate data were not available for Kuparuk.

Other Alaska gas prices were based on the *U.S. Energy Sourcebook* unit prices and are shown in column 3 of Table I-8. All of the unit price data are given for comparative purposes in Table I-8.

Table I-8
Natural Gas Price Data
 (dollars per thousand cubic feet)

<i>Year</i>	<i>Sohio</i>	<i>Arco</i>	<i>Sourcebook</i>
1987		\$ 1.14	\$.50
1986	\$ 1.06	1.16	.74
1985	1.06	1.28	.73
1984	1.06	1.10	.73
1983	1.97	1.03	.63
1982	2.20		.62
1981	2.08		.73
1980	1.96		.52
1979	2.00		.52
1978	2.02		.40
1977	na		.39
1976			.30
1975			.17
1974			.18
1973			.15
1972			.24
1971			.25
1970			.25
1969			.25

na. Not available.

Multiplying the unit price data from Table I-8 times the production data from Table I-5 gives an estimate of total revenues. The revenue estimates for natural gas are given in Table I-9.

A comparison of Table I-9 with Table I-7 shows that natural gas revenues are not significant in dollar terms for the Alaska North Slope. Hence, the inability to subdivide ANS natural gas revenues between Prudhoe Bay and Kuparuk will not have a meaningful effect on the analysis. By contrast, natural gas revenues are significant for the remainder of Alaska. In some years they account for more than one-half of the reported revenues.

Table I-9
Natural Gas Revenue Data
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Other Alaska</i>	<i>Total</i>
1987	\$ 91	\$ 117	\$ 208
1986	80	145	225
1985	68	165	233
1984	46	154	200
1983	49	128	177
1982	79	121	200
1981	69	131	200
1980	95	80	175
1979	51	87	138
1978	41	63	104
1977		61	61
1976		44	44
1975		24	24
1974		20	20
1973		17	17
1972		26	26
1971		27	27
1970		24	24
1969		11	11

Combining natural gas revenues from Table I-9 with the crude oil revenues reported in Table I-7 yields the total revenue estimates for each major area in Alaska. These estimates are shown in Table I-10. It is these revenue estimates that form the basis for the profit analysis which follows. To obtain profit, it is necessary to deduct expenses incurred to earn the revenues reported in this section. Estimation of these expenses is the next topic in this report.

Table I-10
Producers' Revenue Data
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Other Alaska</i>	<i>Total</i>
1987	\$5,786	\$ 942	\$ 349	\$7,077
1986	3,809	575	336	4,720
1985	8,668	1,145	508	10,321
1984	8,888	685	622	10,195
1983	8,872	631	667	10,170
1982	9,921	528	795	11,244
1981	11,734		1,004	12,738
1980	8,399		364	8,763
1979	5,187		372	5,559
1978	1,628		354	1,982
1977	631		323	923
1976			338	338
1975			353	353
1974			331	331
1973			249	249
1972			234	234
1971			245	245
1970			245	245
1969			200	200
Totals	\$73,523	\$4,507	\$ 7,889	\$85,918

II. PRODUCTION EXPENSES

Production expenses fall into nine major categories: depreciation, severance taxes, operating expenses, windfall profit taxes, exploration costs, overhead, interest, state and federal income taxes. Federal income taxes, severance taxes and depreciation are larger in amount relative to the other expenses. Overhead, interest and state income taxes are relatively low. The ability to estimate each of these cost categories accurately varies. The most difficult to estimate are overhead and interest. Fortunately, these are relatively small in amount. Severance taxes and depreciation are relatively easy to estimate. Federal income tax estimates depend on several assumptions. The effect of the assumptions on reported profit is tested later in this technical discussion.

Each of the expense categories and the method of determining the expense is discussed in this section.

DEPRECIATION

Depreciation represents a pro rata share of the initial cost of the investment in drilling, lease acquisition, production facilities and other similar costs over the periods or products that benefit from those investments. Depreciation expense also includes a provision for future dismantlement of the facilities and for restoration of the affected sites. Unlike most other expenses, depreciation does not require a current outlay of cash; it is a current accounting for a prior or an anticipated outlay.

There were three company sources for estimates of depreciation on the Alaska North Slope: (1) BP America's 1987 annual report, (2) Sohio's annual reports from 1977 to 1986, and (3) Arco's 10-K's. In addition, the public data reported here were compared to Alaska property tax information. The results

suggest that use of private data would tend to support the findings reported here. The data and the limitations of the data from each source is addressed in turn.

In its 1987 Annual Report, BP America provided an estimate of its 1986 and 1987 Alaska depreciation which, when divided by its Alaska production, gave a per barrel depreciation amount. However, when BP purchased the outstanding shares of Sohio, it paid a premium over the book value of the assets of Sohio. BP added this premium to its asset base and depreciated this premium along with the cost of the assets. As a result, BP America's Alaska depreciation reflects not only a portion of the costs actually incurred in Alaska, but an additional amount which reflects payments to Sohio shareholders. This latter amount was not part of the cost to acquire oil producing facilities in Alaska. Rather, it reflects BP's purchase of shares from Sohio stockholders. The amortization of this cost is not a cost of operating BP America's Alaska properties, but rather is a transfer payment.⁶ As a result, BP America's depreciation numbers overstate amortization of the costs incurred in Alaska and would understate profit.

In its annual reports for 1981 to 1986, Sohio provided a per barrel total production cost amount with and without depreciation. Subtracting the reported production costs without depreciation from production costs with depreciation yields the depreciation per barrel for Alaska production.

Certain of Arco's 10-K reports stated its depreciation charge for Alaska production activities as a total dollar amount. Dividing these amounts by each year's Alaska production volumes gave an estimate of Arco's per barrel Alaska depreciation. This is referred to below as the Arco production-based estimate.

⁶See Barclay's de Zoete Wedd 1988 report on British Petroleum, p. 4, for the reasons why BP was willing to pay a premium for the remaining outstanding shares of Sohio.

Arco's 10-K also gave its Alaska producing property plant and equipment. When these amounts were divided by Arco's proved reserves each year, an alternate estimate of per barrel depreciation was obtained. This is referred to as Arco's reserve-based estimate. These are composite estimates for all Alaska production, so that adjustments are necessary to obtain estimates for crude oil for each significant field. The alternate estimates are given in Table II-1.

Table II-1
Unit Depreciation Data
(\$ per equivalent barrel)

Year	BP America	Sohio	-----Arco-----	
			Production	Reserves
1987	\$ 2.83		\$ 2.21	2.49
1986	2.26	\$ 2.15	2.56	2.62
1985		1.51	2.47	2.47
1984		1.34	1.65	2.17
1983		1.14	1.81	1.92
1982		1.11	1.56	1.73
1981		1.07	1.30	1.23
1980		1.05		.96
1979		.90		
1978		.84		

These depreciation numbers reflect a weighted average of both Kuparuk and Prudhoe Bay. It is generally recognized that Prudhoe Bay depreciation is lower than Kuparuk. For example, Barclay's de Zoete Wedd (1988) reported Prudhoe Bay depreciation in 1987 at \$2.00 per barrel and Kuparuk at \$3.80. If Barclay's estimates are correct, and assuming that Arco's depreciation is approximately equal to Sohio's, Arco's 1987 weighted average depreciation per barrel should equal:

$$\frac{\$3.80 \times 122 + \$2.00 \times 340}{122 + 340} = \$2.475$$

where 122 and 340 represent Arco's daily average production from Kuparuk and Prudhoe Bay (plus Lisburne) fields as shown in Table I-1, above. Based on this calculation, \$2.475 should be the weighted average per barrel depreciation shown in Arco's annual reports. However, Table II-1 suggests that Arco's

weighted average depreciation is about \$2.21 to \$2.49. Averaging these two estimates gives \$2.35, which is probably the best estimate of Arco's North Slope production depreciation available from Arco's financial statements.⁷ This suggests that the \$3.80/\$2.00 estimates of depreciation for each field are too high.⁸

Given that Sohio's weighted average depreciation number for 1986 was \$2.15 and that was an average of the lower-depreciation Prudhoe Bay and the higher-depreciation Kuparuk, it is likely that Arco's 1986 Prudhoe Bay depreciation was no more than \$2.15 per barrel. This amount is slightly higher than the Barclay's estimate. Presumably, Sohio's depreciation for Prudhoe Bay alone would be lower than \$2.15, so the basis used here could result in an understatement of profit. Assuming Prudhoe Bay depreciation is \$2.15 per barrel, then we can solve for Kuparuk using the equation:

$$462 \times \$2.35 = 122 X + 340 \times \$2.15$$

$$X = \underline{\$2.91}$$

This equation states that Arco's weighted average depreciation per barrel (\$2.35) should equal the Kuparuk production times the unknown depreciation for Kuparuk plus the estimated \$2.15 per barrel depreciation for Prudhoe Bay. The result suggests a \$2.91 per barrel depreciation estimate for Kuparuk.

If Kuparuk depreciation is \$2.91 per barrel, then Prudhoe Bay depreciation per barrel for the years when Kuparuk and Prudhoe Bay were both in production is as given in Table II-2, below. The numbers in Table II-2 should be compared

⁷Salomon Brother's financial analysis of Arco's operations states that Arco's Alaska depreciation is lower than Sohio's. This is the opposite of the data from the financial statements. Public data are not available which would enable us to resolve this disparity. The data in this report are based on the higher estimate from the 10-K's, even though this may overstate depreciation and understate profit.

⁸Salomon Brothers Inc. reported an estimate of \$1.60 per barrel 1985 depreciation for Prudhoe Bay and \$1.75 for 1987. They reported 1985 Kuparuk depreciation at \$3.75 per barrel and 1986 at \$3.55. This confirms the suggestion that Barclay's Prudhoe Bay depreciation is too high. The effects of alternate depreciation estimates on the reported profit for each field are discussed in Section III.

with other sources. For example, *Petroleum Intelligence Weekly* estimated Prudhoe Bay depreciation at \$2.25 in 1987, \$2.17 in 1986 and \$1.53 in 1985. Salomon Brothers estimated Arco's Prudhoe Bay depreciation at \$1.80 in 1987, \$1.75 in 1986 and \$1.60 in 1985.

Table II-2
Estimated Prudhoe Bay Depreciation
(**\$ per barrel**)

<i>Year</i>	<i>Amount</i>
1987	\$ 2.15
1986	2.25
1985	1.75
1984	1.44
1983	1.29
1982	1.19
1981	1.05
1980	.98
1979	.78
1978	.73
1977	.38

These data are higher than Sohio's reported weighted average depreciation charges, but appear more reasonable than the Barclay's numbers. The numbers are lower than Arco's weighted average, which is consistent with expectations. Moreover, they are higher than the Salomon Brothers numbers. In brief, depreciation based on these numbers is a "middle-of-the-road" approximation.

Since depreciation expense for each field was computed using a weighted average based on working interest production from each field, total depreciation for both fields taken together will be approximately the same. That is, Prudhoe Bay might be assigned too much depreciation as a result of this process, but that will be offset by lower depreciation charges to Kuparuk. The "bottom-line" effect of this is discussed in Section III.

Prior to the start of Kuparuk production, depreciation estimation is simplified. For each of the years 1978 through 1981, a weighted average of the reported per-barrel depreciation numbers for Arco and Sohio was used. There was one

estimate of Sohio's depreciation each year. There were three Arco estimates in 1981, two in 1980, and one for each of 1978 and 1979. It was assumed that Sohio's depreciation number was applicable to 72% of field production and Arco's to 28%. This ratio reflects Sohio's 53% of overall production to the total production for which depreciation data are available (53% Sohio; 21% Arco). It is assumed that the missing data equals a weighted average of the available data.

For 1977, the only depreciation estimate was that based on Arco's production. Lacking any alternate estimate, it was used for that year. Since production in that year was relatively low, it is unlikely that changing the estimate by a reasonable amount will have a substantial effect on the results.

Per-barrel depreciation estimates for Prudhoe Bay are reported in Table II-2, above. Kuparuk depreciation is estimated at \$2.91 per barrel. Although this estimate of Kuparuk depreciation is lower than that reported by some of the financial analysts discussed above, Barclay's reports that Kuparuk had an original estimated 1.9 billion barrels of recoverable crude oil. Given estimated investment in Kuparuk of \$4.3 billion a depreciation charge of \$2.28 per barrel (i.e. \$4.3 billion/1.9 billion) is indicated. The \$2.91 per barrel estimate may result in understatement of Kuparuk profit.

Total depreciation for each field is the product of crude oil production times the per-barrel amount. For non-ANS production, gas is converted to equivalent barrels using the standard 6 mcf of gas = 1 bbl. crude oil energy content ratio. It was assumed that non-ANS depreciation per barrel was 1/3 of ANS per-barrel depreciation. Use of this assumption yields total depreciation amounts that are relatively close to what one would expect given non-ANS investment and production levels. Total depreciation amounts for each year are presented in

Table II-3. These data represent the depreciation expense numbers included in the production profit estimates in Section III.

Table II-3
Total Depreciation Expense
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Total Alaska</i>
1987	\$1,074	\$ 263	\$ 1,394
1986	1,110	253	1,418
1985	873	204	1,123
1984	710	117	866
1983	632	112	779
1982	581	83	698
1981	510		540
1980	476		504
1979	320		345
1978	254		280
1977	38		53
1976			16
1975			16
1974			16
1973			16
1972			16
1971			16
1970			17
1969			14
Totals	\$6,579	\$1,032	\$8,127

SEVERANCE TAXES

Severance taxes are levied on the gross value of production which accrues to producers (i.e., working interest production). In Alaska, prior to 1981 severance taxes were 12.25% of production. Subsequent to 1981, the amount was revised to 15% of production (except that it remained 12.25% for the first five years of a field's commercial production). An economic limit factor is applied to production from each field which causes the actual severance tax to be lower than the statutory rate. The 1981 Legislation suspended the application of the economic limit factor at Prudhoe Bay until mid-1987. Prior to 1981, it was estimated that the severance tax on Prudhoe Bay production averaged approximately 11%. From 1982 to mid-1987, the Prudhoe Bay severance tax was estimated at 15%. From the middle of 1987 on, the Prudhoe Bay severance

tax was estimated at 12.25%.⁹ Severance taxes on Kuparuk production have been estimated to range between an effective rate of 8% and 9%. A 9% rate was used for this study for Kuparuk. Recent severance tax returns suggest that by 1987 the economic limit factor reduced severance taxes on non-ANS Alaska production to close to zero. The effect of changes in the non-ANS depreciation amounts does not have a meaningful impact on reported profit.

To determine profit from oil producing activities, it is necessary to deduct severance taxes from revenues. Severance taxes are not reported separately for Alaska production in the annual reports of the producers. Therefore, the effective severance tax rates were applied to revenues reported here to obtain estimated severance tax expense for 1977 through 1987 for each field. For prior years, Alaska Department of Revenue reported collections were used as the severance tax expense. This amount corresponds closely to the expense that would be estimated if the statutory rate were applied to the production values.

The Alaska Department of Revenue reports severance tax collections from oil production in Alaska. Over time, severance tax expense as deducted to compute profit should tend to equal severance tax collections by the state. There is one significant wrinkle in this comparison. In 1975, the State levied a reserves tax which was allowed as a later credit against severance tax due later. The amount of the reserves tax was \$493.7 million. This tax was considered a credit against severance tax payments due. Thus, when comparing severance tax collections to recorded expense, it is necessary to include this \$493.7 million as a collection.

The estimated severance taxes for Prudhoe Bay, Kuparuk, non-ANS, and the total expense are summarized in Table II-4. These amounts are compared to

⁹Effective severance tax rates are based on *Petroleum Intelligence Weekly* (February 1, 1988).

severance tax collections, including the reserves tax, as reported by the Department of Revenue. The results of the comparison indicate that the estimates are quite close to collections as they should be over time.¹⁰

Table II-4
Severance Taxes
(millions of dollars)

Year	Prudhoe	Kuparuk	Non-ANS Alaska	Total Expense	Revenue Collections#
1987	\$ 787	\$ 85	\$ 0	\$ 871	\$ 649
1986	571	52	0	623	1,108
1985	1,300	103	0	1,403	1,389
1984	1,333	62	0	1,395	1,393
1983	1,331	57	0	1,388	1,494
1982	1,488	48	0	1,535	1,572
1981	1,291		0	1,291	1,170
1980	924		0	924	507 *
1979	622		0	622	174 *
1978	195		0	195	108 *
1977	76		0	76	295 *
1976			28	28	251 *
1975			27	27	27
1974			22	22	22
1973			11	11	11
1972			11	11	11
1971			11	11	11
1970			8	8	8
1969			6	6	6
Totals	\$9,918	\$ 406	\$ 124	\$10,441	\$10,206

* Reflects differences due to reserves tax included in 1976 and 1977 collections but credited against later liabilities.

#Alaska revenue data are reported on a fiscal year basis. Company expense data are reported on a calendar year basis. This difference can affect some of the comparisons.

It is likely that some of non-ANS production during 1977 through 1987 incurred a severance tax liability. However, the amounts are too low to affect the analysis. Total severance tax expense reported in the analysis of profit is \$10,441 million. Total actual tax collections amount to \$10,206 million. The difference is 2.3%. It is possible that this difference is due to overstatement of effective severance tax rates or the delay between the time when severance

¹⁰Expense should exceed collections because collections are reported when received by the Alaska Department of Revenue and expenses are reported when the related production occurs.

taxes are due and when they are collected. The difference may also be due to the revenue estimates used. In any event, it is unlikely that the differences will have a significant effect on the results of the analysis.

OPERATING EXPENSES

Operating expenses are those costs which are necessary to continue production from an oil or gas field. They include well workover costs, fuel, maintenance and similar items. Information on these costs for the years 1980 to 1986 is available in the corporate annual reports of Sohio. Financial analyst reports include estimates of operating expenses as determined through meetings with company officials as well as based on their evaluation of operating costs.

For this report, operating expenses reported by Sohio were analyzed first. Sohio reports operating expenses combined with production taxes, windfall profit taxes and its net profits interest payments to BP America. It was necessary to separate production and windfall profit taxes from Sohio's reported data since these taxes are reported on another line in this income statement. The net profits interest payments to BP America would be an expense to Sohio, but a revenue item to BP America. This is a transfer payment between two field owners. The transfer payment needs to be cancelled when estimating income for the total project.

Net profits interest payments were reported in the notes to Sohio's financial statements. Severance taxes were estimated using the effective severance tax rates times the reported revenues. Windfall profit taxes were reported on a per-barrel basis in Arco's annual reports. These estimates were used to obtain an estimate of Sohio's windfall profit taxes. As described below, the resulting estimated windfall profit tax expense was lower than the reported windfall profit

tax collections by the U.S. Internal Revenue Service. As a result, the estimates of operating expenses may be higher than actual.

Table II-5 summarizes Sohio's reported production expenses, the computed estimates of severance and windfall profit taxes and the net profits interest payments to BP. The last column of Table II-5 is estimated operating expenses for the ANS based on the Sohio data.

Table II-5
Sohio's Operating Expenses
(millions of dollars)

<i>Year</i>	<i>Production Costs</i>	<i>Severance and Windfall Profit Taxes</i>	<i>Net Profits Interest</i>	<i>Operating Expenses</i>
1986	\$ 727	\$ 271	\$ 44	\$ 412
1985	1,216	680	108	428
1984	1,113	649	36	428
1983	1,021	699	0	322
1982	1,685	1,199	92	394
1981	2,550	2,030	153	367
1980	1,181	862	145	174

The resulting operating expenses were analyzed to see if they were mathematically related to revenues or production. It appeared that the operating expenses were not related to revenues and were only weakly related to production levels. Regression analysis, a statistical technique used to compare two sets of data (such as operating expenses and revenues), found no relationship between the numbers. This leads to the suggestion that these expenses are fixed costs. Further study of the expenses showed that they increased when the Prudhoe Bay waterflood project was installed and when the gas reinjection recovery program was installed. This further supports the suggestion that these costs are fixed with respect to annual production and revenues.

The best available overall estimate of production costs, then, is based on the relationship of Sohio's interest in Prudhoe Bay field. Thus, total ANS operating

expenses are estimated as equal to Sohio's operating expenses divided by Sohio's interest in Prudhoe Bay field. These expenses were subdivided between Prudhoe Bay and Kuparuk based on relative revenues from each field. Admittedly, this may misstate the precise relationship since operating expenses are not a function of annual revenues. However, there are no other direct operating expense data sources available publicly from the companies. The results of the calculations used for this estimate are presented in Table II-6.

Table II-6
Estimated Total Operating Expenses
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Total</i>
1987	\$ 890	\$ 218	\$1,137
1986	662	152	845
1985	685	160	867
1984	726	120	850
1983	541	96	659
1982	651	92	771
1981	692		722
1980	328		335
1979	307		318
1978	261		289
1977	76		95
1976			28
1975			27
1974			23
1973			16
1972			14
1971			15
1970			15
1969			12
Totals	\$5,820	\$ 837	\$7,038

Production costs for 1987 and for 1977 through 1979 were estimated based on an approximate relationship between revenues and these costs. Given the lack of other company data on these costs, reliance on revenues is one way available to approximate the operating expenses for the missing years.¹¹ There is a significant increase in the estimated operating expenses between 1980 and

¹¹Although production costs are not related to revenues mathematically, there are relatively few options available for estimating costs attributable to each field. Since production costs are low relative to revenues, it is probable that the effect on reported profit is minor.

RTSXMB 519730

1981. This is probably due to the differences in windfall profit taxes included in the Arco data used to derive the windfall profit tax number and the Sohio data used as a basis for operating costs before deducting windfall profit taxes. As noted in the section on windfall profit taxes, Arco-based windfall profit tax numbers result in an expense that is lower than when using the I.R.S. collection data. It is possible that the use of Arco windfall profit tax numbers in the operating cost computation overstates operating costs with a resulting understatement of profit.

Other analysts such as *Petroleum Intelligence Weekly* and Salomon Brothers estimate that operating costs amount to an average of \$1 per barrel of ANS crude oil production. *International Petroleum Finance* estimates operating costs at \$.91 per barrel. The results here average \$1.08 per barrel. Therefore, even though the expense number is calculated based on a number of assumptions, the outcome of the calculations follows closely, and conservatively, the costs indicated by other observers.

For 1984 to 1986, the operating costs per barrel for the Prudhoe Bay field should be greater than in prior years due to installation of the waterflood program. Since the method used here is based on a combined operating cost for Prudhoe Bay and for Kuparuk, it is probable that the costs for Kuparuk are somewhat overstated during 1984 to 1986 and the costs for Prudhoe Bay are understated by a like amount. The results could be a shifting of profit from Kuparuk to Prudhoe Bay in the amount of up to \$100 million over the six-year period of Kuparuk operations. It does not appear that this is a significant amount relative to the profit for each field.

Production costs also include property taxes. Company data do not show the property taxes in Alaska separate from other production costs. Therefore, it is necessary to use alternate sources. Barclay's estimated Prudhoe Bay property

taxes at \$.50 per barrel and Kuparuk at \$.30. Non-ANS was estimated at \$.25. The results were compared to Department of Revenue data and are comparable.

Production costs, net of property taxes, are obtained by deducting the property tax collections from the production costs reported in Table II-6. Table II-7 shows the Alaska and municipal property taxes for the areas covered in this report. Table II-8 gives the production expenses net of property taxes.

Table II-7
Property Taxes
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Total</i>
1987	\$ 150	\$ 44	\$ 197
1986	148	41	192
1985	150	35	188
1984	148	20	172
1983	147	17	159
1982	147	14	165
1981	146		151
1980	146		152
1979	123		130
1978	104		113
1977	30		31
1976			12
1975			13
1974			13
1973			13
1972			13
1971			13
1970			14
1969			13
Totals	\$1,438	\$ 171	\$1,754

RTSXMB 519732

Table II-8
Operating Expenses
Net of Property Tax
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Total</i>
1987	\$ 740	\$ 174	\$ 940
1986	514	110	653
1985	535	125	679
1984	578	100	678
1983	394	77	500
1982	504	78	606
1981	546		571
1980	182		183
1979	184		188
1978	157		176
1977	46		63
1976			14
1975			15
1974			10
1973			3
1972			1
1971			2
1970			1
1969			1
Totals	\$4,382	\$ 666	\$5,284

WINDFALL PROFIT TAXES

The Crude Oil Windfall Profit Tax Act of 1980 levied a tax on the "windfall profit from a barrel of crude oil." The windfall profit was defined as the difference between the base price (essentially the price before oil price decontrol) and the selling price. The tax was in effect until 1988 although crude oil price declines rendered the effective amount of the tax at zero for years after 1985. In addition, ANS fields outside the Sadlerochit reservoir were exempt from the tax.

There are two primary sources of data concerning the windfall profit tax on Alaska crude oil production. The first is Arco's reported windfall profit tax per barrel of Alaska crude oil production. The second is the U.S. Internal Revenue Service *Statistics of Income Bulletin* which reported the aggregate windfall profit tax collections on ANS crude oil as a separate line item. Arco's per barrel windfall profit tax statistics are reproduced in Table II-9.

RTSXMB 519733

Table II-9
Windfall Profit Tax per Barrel
Arco Annual Report Data
 (\$ per barrel)

<i>Year</i>	<i>Amount</i>
1985	\$.05
1984	.11
1983	.42
1982	1.59
1981	4.80
1980	2.03

To obtain the total windfall profit tax attributable to Prudhoe Bay, the Arco per barrel numbers were multiplied by field production. In addition, the Arco per barrel numbers were multiplied by the ratio of the all-company average field price to the Arco reported field price. This latter adjustment is designed to reflect the fact that other producers sold their ANS crude for a price that was different than that reported by Arco.¹²

Estimates of non-ANS crude windfall profit taxes were constructed by estimating the windfall profit on this crude and multiplying by a composite windfall profit tax rate. It was assumed that 1/2 of the crude was taxed at the 70% rate for old oil and 1/2 was taxed at a 30% rate. The base price was estimated as equal to the 1979 Cook Inlet price reported by DeGolyer and MacNaughton, adjusted for inflation for 1980 through 1985. The per barrel numbers obtained by this method were as follows in Table II-10:

Table II-10
Non-ANS Windfall Profit Tax
 (\$ per barrel)

1985	\$ 0.00
1984	1.42
1983	2.58
1982	5.46
1981	9.42
1980	1.91

¹²See Production Revenue section for further detail on this issue.

These per barrel amounts were multiplied by reported non-ANS production from column 1 of Table I-4 to obtain total windfall profit taxes for other Alaska production.

Estimated windfall profit taxes for Prudhoe Bay field and for all of Alaska are reproduced in column 1 of Table II-11. The computed amounts were compared to the reported collections from the *Statistics of Income Bulletins* shown in column 2 of Table II-11.

Table II-11
Windfall Profit Tax Expense
(millions of dollars)

<i>Year</i>	<i>Estimated for Prudhoe Bay</i>	<i>U.S. Internal Revenue Service ANS Collections</i>	<i>All Alaska</i>
1985	\$ 26	\$ 39	\$ 39
1984	57	211	235
1983	215	426	475
1982	827	1,375	1,491
1981	2,487	3,089	3,314
1980	1,006	797	861
Totals	\$4,618	\$5,937	\$6,415

Table II-11 shows that the U.S. Internal Revenue Service reported higher ANS windfall profit tax collections than those obtained using the Arco data adjusted for estimated price differences among the producers. The possibilities for these discrepancies are two-fold. First, the Arco-based revenue estimates may be too low as noted in the section on Production Revenue. Second, Arco may have had available to it adjustments to the windfall profit tax arising from the net income limitation provisions of the tax act. This part of the Act stated that windfall profit should not exceed 90% of the net income per barrel based on statutory computational rules. The net income limitation provision would not have been captured in the Internal Revenue Service data.

RTSXMB 519735

Column 3 of Table II-11 is the sum of the U.S. Internal Revenue Service reported ANS windfall profit tax collections plus the windfall profit taxes estimated for non-ANS production.

The difference between the two data sources is \$1.3 billion. In the interest of providing a more conservative estimate of profit from Alaska oil operations, the higher figures of the Internal Revenue Service are used as the basis for Alaska windfall profit taxes.

EXPLORATION EXPENSES

Exploration expenses represent the costs incurred in finding new oil and gas deposits as well as certain costs incurred in defining an existing deposit. Data were not available to assign exploration costs to specific fields during this period. Moreover, there are few data series which overlap, so comparisons across estimates are not possible.

The U.S. Bureau of the Census provides data on Alaska oil industry exploration expenditures for 1978 to 1982 through its *Current Industrial Surveys*. The American Petroleum Institute *Joint Association Survey* provided the 1984 estimate of exploration expenditures. Both of these sources separated offshore expenditures from onshore. Presumably, the offshore expenditures were in Federal waters. These are the best sources of exploration expenditure data available, but they only were available for the years indicated.

For years prior to 1978, it was estimated that exploration expenditures totalled \$25 million per year. This amount was compared to exploration drilling data obtained from the Alaska Oil and Gas Conservation Commission. The AOGCC provides numbers of wells drilled. The estimated exploration expenditures in 1969 to 1977 provided here would have financed the levels of drilling indicated by the AOGCC.

For 1983 and for 1985 to 1986 it was assumed that exploration costs equalled double the amount that Sohio reported as Alaska exploration expenses. It was assumed that 1987 exploration equaled 1986, although this is a conservative estimate. Comparing the amounts provided to the AOGCC drilling statistics indicates that these amounts would have easily financed the exploration activities reported by the AOGCC. Table II-12 shows the estimates of exploration expenses included in determining Alaska oil industry profit.

Table II-12
Exploration Expenses
(millions of dollars)

<i>Year</i>	<i>Amount</i>	
1987	\$ 288	
1986	288	
1985	514	
1984	258	
1983	818	
1982	647	
1981	419	
1980	176	
1979	174	
1978	274	
1969 - 1977	25	annually
Total	\$ 4,081	

OVERHEAD AND INTEREST EXPENSES

Overhead expenses are those that by their very nature cannot be traced directly to a particular activity. These costs are common to all activities in the company. The generally accepted accounting procedure is to allocate these costs to each activity that benefits from the cost on some basis that reflects either benefits received or cause-and-effect.¹³ Frequently, as here, allocations are made in more than one step. Here, the first step is to allocate company overhead to Alaska operations. The second step is to allocate overhead to each field in Alaska.

¹³See, for example, E. Deakin and M. Maher, *Cost Accounting 2nd. ed.* (1987), pp. 96 - 101. This topic has been addressed in detail by the former U.S. Cost Accounting Standards Board. The Cost Accounting Standards Board methodology is followed as closely as possible based on available data.

Sohio is the only producing company operating in Alaska from which sufficient data were available to make an allocation of overhead to Alaska activities based on assets and on revenues. In its corporate annual reports, Sohio presents segment information which, among other things, states Sohio's "Corporate and other" expenses. This line item was used as a proxy for the overhead cost.

To allocate this overhead, a two-factor formula was used. The two factors are value of crude production in Alaska to all company sales, and oil and gas property in Alaska to all Sohio property plant and equipment other than property plant and equipment related to the company's "corporate and other" activities.

Sohio data were available for 1977 through 1986. In 1987, BP America succeeded Sohio as a result of BP's buyout of the minority interest in Sohio. This purchase was accounted for by adding the extra funds paid to Sohio shareholders in excess of the book value of the assets received being attributed to the book values of the Sohio assets acquired. In effect, BP increased the accounting-based cost of its Alaska assets by a proportional amount of its payment to Sohio shareholders. This payment did not increase the actual costs expended in Alaska. Rather, it represented a transfer from BP to the former Sohio shareholders. As a result, the 1987 data necessary to perform the allocation would be affected by the amount of this transfer payment. Since this payment would result in attributing costs disproportionately to the actual costs incurred in Alaska, 1987 overhead was estimated by taking 1986 overhead and adding 4.5% for inflation.

A third factor commonly used in these formulas is payroll. These data are not publicly available. If the payroll data were available, the resulting allocation would be lower than that reported here because Sohio has proportionately fewer

RTSXMB 519738

employees in Alaska than the average of its assets and sales. The allocation method here used the value of Alaska production relative to total company sales. This ratio includes sales that have not been made to third parties. If third-party sales only were included, the allocation of overhead to Alaska operations would be lower than that reported here.

The result of this calculation is the first step in the allocation of Sohio overhead to all Alaska operations. Dividing the resulting allocation by Sohio's proportionate share in the Prudhoe Bay field yields an estimate of the total overhead attributable to Alaska by all producers. This is based on the assumption that other producers have a similar overhead structure to Sohio's and that the Prudhoe Bay ratio is a reasonable basis for estimating overall overhead. More complex allocations which include estimates of Kuparuk production have insignificant effects on the reported allocation.

To allocate to Prudhoe Bay and Kuparuk, overhead allocated to Alaska was subdivided in proportion to the revenues reported for Prudhoe Bay and Kuparuk. The original data used for the allocations and the results are give in Table II-13.

Table II-13
Overhead Allocations
(millions of dollars)

Year	—Sohio Total—			—Allocated to—		Total
	Overhead	Assets	Revenues	Prudhoe	Kuparuk	
1987				\$ 109	\$ 20	\$ 139
1986	\$ 234	\$ 14,006	\$ 10,022	105	20	133
1985	270	16,468	13,818	139	25	173
1984	160	16,421	12,251	89	11	106
1983	172	15,181	12,067	93	11	111
1982	132	14,347	13,529	77	8	91
1981	86	13,096	14,140	51		55
1980	24	8,506	11,346	15		16
1979	4	7,927	11,346	2		2
1978	-1	8,107	8,222			-1
1977	6	7,578	3,523	2		3
Totals				\$ 681	\$ 94	\$ 830

This allocation assumes that overhead is proportional between Kuparuk and Prudhoe Bay. Such an assumption would usually be consistent with general accounting practices.

For lack of any data on the subject it was assumed that overhead for non-ANS activities was proportional to the revenues for those activities.¹⁴ To obtain total overhead attributable to Alaska, the Prudhoe Bay and Kuparuk overhead were increased proportionately by the ratio of total Alaska production revenues to Prudhoe Bay and Kuparuk revenues. For years prior to 1977, overhead was estimated as a percentage of revenues based on the revenue percentage over the years 1977 through 1987. Overhead in each of the years prior to 1977 averaged less than \$150,000.

Although these allocations are subjective and complex, they suggest that the overhead amounts are not so highly significant as to have a material effect on estimated profit. Aggregate overhead over the period of ANS production is estimated at \$830 million. This is on the order of 2% of total profit. Even major changes in this number will have a minor effect on total profit.

To test one aspect of a source of variation in the overhead allocations, a composite estimate based on Arco's reported corporate and other expense using a two-factor formula was calculated. For most of the period at issue, Arco did not report its Alaska assets separately in its annual reports. These data were obtained from its SEC Form 10-K, Schedule VI.¹⁵ Arco's total assets were obtained from its annual report segment disclosures. Total revenues were

¹⁴Non-ANS overhead accounts for approximately 10% of the total overhead reported here. Similarly, non-ANS production is a small portion of total production in Alaska. In addition, as noted for the ANS, overhead is a small portion of overall costs and revenues. The effect of misstatements of the overhead will not have a significant impact on this analysis.

¹⁵In 1980 and 1981, Arco reported Alaska producing property plant and equipment in its annual report. The amounts were \$1,087.7 million and \$1,451.1 million respectively. The company reported Alaska property in its 10-K schedule for the same years as \$1,789.2 million and \$2,273.5 million respectively. The differences are substantial which suggests that the two series may not be comparable.

obtained from the annual report, but Alaska revenues had to be estimated by multiplying reported per barrel prices by reported Alaska production. Assuming that Arco accounted for 21% of Alaska activities and Sohio 51%, weighting the two overhead estimates gave a composite amount of \$1,233 million over the period 1977 - 1987.

A second test of overhead variation is to construct an estimate using a payroll factor in the allocation formula. If Alaska payroll is assumed equal to 5% of each company's payroll, estimated overhead attributable to Alaska is \$357 million over the period 1977 through 1987. The overhead amount included in the reported profit estimate is midway between these two numbers. Over the same period, the overhead estimate in this report averages 16.1¢ per barrel.

Interest expense was handled in a similar manner. Again, interest costs were based on data from Sohio's corporate annual reports because that was the only readily available source.¹⁶

Net interest expense for Sohio was reported in Sohio's segment disclosures in its annual reports or on the face of its income statements for 1977 through 1986. Since interest costs are related to the investment in assets rather than to sales, allocations of interest to Alaska were based on the ratio of property plant and equipment in Alaska to total company property plant and equipment. The result of this apportionment was the estimated interest expense attributable to Alaska.

The second step of the interest allocation required producing an estimate of interest attributable to Alaska by all producers. This was based on dividing

¹⁶Arco reports some of the data required for this calculation, but the data are reported in different places which may not be consistent as noted in the overhead allocation discussion. It appears that Arco and Exxon experienced a lower overall rate of interest than Sohio. Therefore, Arco's and Exxon's interest costs should be lower than Sohio's. The amounts involved are small relative to the total reported income.

Sohio's assumed Alaska interest expense by its proportional interest in the Prudhoe Bay field. As with the overhead allocation, the results were not particularly sensitive to further refinement. The estimated total Alaska interest expense was subdivided between properties based on depreciation expense. This is more appropriate than sales because depreciation is considered more closely related to assets than to sales. Sohio's total company interest and assets and the resulting estimated interest allocations to the Kuparuk and Prudhoe Bay fields are given in Table II-14.

Table II-14
Interest Allocations
(millions of dollars)

Year	---Sohio Data---		---Allocated to---		Total
	Net Interest	Assets	Prudhoe	Kuparuk	
1987			\$ 146	\$ 32	\$ 192
1986	\$ 242	\$14,006	139	32	183
1985	299	16,468	141	33	183
1984	242	16,421	119	20	148
1983	254	15,181	119	21	150
1982	300	14,347	139	20	171
1981	46	13,096	17		18
1980	22	8,306	10		11
1979	357	7,927	156		167
1978	458	8,107	203		247
1977	246	7,578	117		177
Totals			\$ 1,306	\$ 159	\$ 1,675

The "net interest" column is Sohio's total corporate interest expense net of interest income. The "assets" column is Sohio's total assets less those designated as assets devoted to "corporate" (i.e., overhead) activities. Sohio's portion of net interest expense was allocated to Alaska based on the formula apportionment. The result was "factored up" to reflect an approximation of the total interest expense incurred by all Alaska producers.

For years prior to 1977, average estimated interest expense allocable to Alaska was less than \$200,000 per year.

RTSXMB 519742

STATE INCOME TAXES

The State of Alaska levies an income tax on the income derived from oil and gas production operations in the State. During the 1977 - 1981 period, this tax was based on a direct measure of the income earned in the state. The statutory tax rate was 9.4% until 1981 when it rose to 11% for that year. Subsequent to 1981, the tax was levied using an indirect method referred to as modified formula apportionment. The latter tax is based not on a direct computation of the revenues accrued less expenses attributable to Alaska, but rather is based on a measure of the proportion of certain Alaska activities to overall company activities. The computed proportion is multiplied by overall company income to derive an estimate of income attributable to Alaska. *Petroleum Intelligence Weekly* suggests that the effective tax rate under this methodology is approximately 3%. As shown in Table II-15, a comparison of tax expense computed at the 3% rate is reasonably close to tax collections.

Individual company data on the Alaska income tax liability is not publicly available. The estimate of Alaska income tax is obtained by multiplying computed Alaska income by the effective tax rates for the periods at issue. The results are reported in Table II-15.

Table II-15
State Income Taxes
(millions of dollars)

<i>Year</i>	<i>Prudhoe Bay</i>	<i>Kuparuk</i>	<i>Total*</i>	<i>Reported Collections*</i>
1987	\$ 83	\$ 10	\$ 92	\$ 128
1986	37	2	37	134
1985	165	19	182	169
1984	171	11	189	265
1983	172	10	174	236
1982	168	8	175	669
1981	669		702	860
1980	550		556	548
1979	367		369	233
1978	67		66	33
1977	30		49	36
Prior to 1977			150	150
Totals	\$2,479	\$ 60	\$ 2,741	3,461

*Alaska revenue data are reported on a fiscal year basis. Company expense data are reported on a calendar year basis. This difference can affect some of the comparisons. The collections include TAPS income taxes which are estimated to total \$900 million.

The estimates differ from collections in part because of differences in the timing of when receipts are received by the State and when the expenses are reported on the income statements. Over the period 1969 through 1987, reported collections totalled \$3.5 billion. The income statements here indicate total expenses of \$3.6 billion, including the \$.9 billion for TAPS. The differences are within a 5% margin of error.

FEDERAL INCOME TAXES

The U.S. government levies taxes on corporate income at statutory rates that ranged from 34% to 48% over the period 1969 through 1987. Under Federal rules, taxable income is net of state income taxes. Certain credits and deductions are allowed in the Federal taxing scheme which reduce the effective tax rates. It has been estimated that during the 1969 through 1980 period, the effective tax rates for oil companies averaged on the order of 29% (*Oil and Gas Journal*, (September 16, 1985), p. 76). This estimate was used for the 1969 to 1976 period.

For Alaska oil income after the start-up of Prudhoe Bay, this estimated Federal rate is unlikely to reflect actual Federal taxes. The taxes currently payable divided by estimated taxable income gives a number referred to as the effective tax rate. One important factor which results in a difference between statutory rates and effective rates is the Federal tax rules designed to provide an incentive to new investment like TAPS and tangible equipment on the North Slope. For example, an investment tax credit equal to 10% of the cost of tangible equipment was in effect during most of this period. This credit would serve to reduce Federal taxable income. That the effective tax rates were lower for Alaska producers may be seen by examining effective tax rates for these producers during the 1977 through 1986 period.

Effective tax rates for the major ANS producers were obtained from their corporate annual reports. The effective rate is the current Federal tax payments divided by reported net income. This information, as available, is reproduced in Table II-16.

Table II-16
Effective Federal Tax Rates

<i>Year</i>	<i>Arco</i>	<i>Sohio</i>	<i>Exxon</i>
1986	-55.49	-52.44	na
1985	40.94	41.53	23.18
1984	33.22	26.56	29.16
1983	19.68	31.60	33.81
1982	17.08	39.06	25.38
1981	16.23	36.41	23.93
1980	16.16	39.37	33.35
1979	12.30	11.22	35.29
1978	6.34	1.34	38.28
1977	na	10.19	na

It is widely presumed that Sohio's financial data was driven almost exclusively by its Alaska operations.¹⁷ For this reason, Sohio's effective tax rates would tend to reflect the actual tax liability for Alaska oil operations during

¹⁷A review of Sohio's corporate annual reports from 1978 through 1986 indicate that over 90% of its profit arose from its Alaska activities.

the 1977 - 1986 period. Many oil companies, including the ANS producers, wrote-off substantial amounts from losing operations. The significant write-offs taken in 1986 resulted in negative Federal taxes for Alaska oil producers who accounted for most Alaska activities. Therefore, a zero effective Federal rate was used in 1986.

Although financial accounting standards for a company require that recognition be given currently to the possibility that some income tax benefits may need to be paid back to the government in the future, it appears from a review of the effective tax rates in Table II-16 that in this industry, the payback period continues to be deferred indefinitely. Use of current effective tax rates for the purposes of this study reflects better the economic consequences to the company of these investments than the use of statutory rates. In future years as tax benefits decline, these producers may be required to pay taxes in excess of the statutory rate.

With the merger of Sohio into BP, the assumption that Sohio's activities reflect Alaska closely would no longer hold. In addition, beginning in 1987, the tax law reduced many of the incentives for new investment. As a result, actual taxes are probably closer to the statutory rate. Therefore, the 34% statutory rate was used for 1987.

The Federal income tax expense used to estimate Alaska oil production income is reproduced in Table II-17.

These data were obtained by multiplying revenues from Table I-10 less expenses (covered in Tables II-3 (depreciation), II-4 (severance taxes), II-6 (operating expenses), II-11 (windfall profit tax), II-12 (exploration expenses), II-13 (allocated overhead), II-14 (allocated interest), and II-15 (state income taxes)) by the related effective tax rates.

Over the entire period 1969 through 1987, Federal income taxes as shown in this report are 32.0% of estimated taxable income. This is higher than the 29% effective rates in the *Oil and Gas Journal* study. The net effect is that the estimates in this report are conservative and may tend to understate actual income.

Table II-17
Federal Income Taxes
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>Kuparuk</i>	<i>Total</i>
1987	\$ 917	\$ 105	\$1,007
1986	0	0	0
1985	2,212	247	2,424
1984	1,469	91	1,627
1983	1,756	102	1,774
1982	2,125	104	2,212
1981	1,971		2,067
1980	2,086		2,110
1979	383		399
1978	9		8
1977	32		52
1976			63
1975			68
1974			66
1973			47
1972			44
1971			47
1970			47
1969			37
Totals	\$ 12,960	\$ 651	\$ 14,099

III. PRODUCTION PROFIT

The result of all of the calculations in Sections I and II is to generate a statement which indicates the profit earned from oil and gas production in Alaska. This part of the report is divided into three parts: (1) profit for Prudhoe Bay, (2) Kuparuk and (3) all production in Alaska.

Table III-1
Profit from Prudhoe Bay Production
(millions of dollars)

1983 - 1987:

	1987	1986	1985	1984	1983
Production Revenue	\$6,573	\$4,327	\$9,847	\$10,097	\$10,079
Expenses:					
Depreciation	1,074	1,110	873	710	632
Operating Expenses	740	514	535	578	394
Overhead	109	104	139	89	93
Interest	146	139	141	119	119
Royalty	787	518	1,179	1,209	1,207
Severance Taxes	787	571	1,300	1,333	1,331
Property Taxes	150	148	150	148	147
State Income Tax	83	37	165	171	172
Windfall Profit Tax			39	211	426
Federal Income Tax	917	0	2,212	1,469	1,756
Profit	<u>\$1,780</u>	<u>\$1,186</u>	<u>\$3,114</u>	<u>\$4,061</u>	<u>\$3,801</u>
Profit per barrel	<u>\$3.55</u>	<u>\$2.40</u>	<u>\$6.25</u>	<u>\$8.26</u>	<u>\$7.75</u>

1977 - 1982:

	1982	1981	1980	1979	1978	1977
Revenue	\$11,271	\$13,330	\$9,541	\$5,892	\$1,849	\$717
Expenses:						
Depreciation	581	510	476	320	254	38
Operating Expenses	504	546	182	184	157	46
Overhead	77	51	15	2	0	2
Interest	139	17	10	156	203	117
Royalty	1,350	1,596	1,143	706	221	86
Severance Taxes	1,488	1,291	924	622	195	76
Property Taxes	147	146	146	123	104	30
State Income Tax	168	669	550	367	67	30
Windfall Profit Taxes	1,375	3,089	797			
Federal Income Tax	2,125	1,971	2,086	383	9	32
Profit	<u>\$3,315</u>	<u>\$3,443</u>	<u>\$3,212</u>	<u>\$3,030</u>	<u>\$ 639</u>	<u>\$ 260</u>
Profit per barrel	<u>\$6.78</u>	<u>\$7.09</u>	<u>\$6.61</u>	<u>\$7.39</u>	<u>\$1.84</u>	<u>\$2.58</u>

Total profit over the eleven year production history of the Prudhoe Bay field are estimated as shown in Table III-2. The profit statements in Table III-1 are based on the producers' interest in the production. This is standard accounting practice, but the methodology excludes royalty interests which are important for the State of Alaska. Royalty interests have been estimated as equal to 1/7 of the producers' working interest less a gathering charge of \$.63 per barrel. The state royalty is added to the producers' revenue to obtain revenues before royalty as shown in Table III-2.

Table III-2
Total Prudhoe Bay Production Profit
1977 through 1987
 (billions of dollars)

Production Revenue	\$ 83.5
Less Expenses:	
Depreciation	6.6
Operating Expenses	4.4
Overhead	.7
Interest	1.3
Royalty	10.0
Severance Taxes	9.9
Property Taxes	1.4
State Income Taxes	2.5
Windfall Profit Tax	5.9
Federal Income Taxes	<u>13.0</u>
Profit	<u>\$ 27.8 Billion</u>
Profit per barrel: <u>\$5.81</u>	

The estimate of profit from the Kuparuk field is also based on the combination of the data from Sections I and II of this report and is reproduced in Table III-3.

Table III-3
Annual Kuparuk Production Profit
1982 through 1987
 (billions of dollars)

	1987	1986	1985	1984	1983	1982
Production Revenue	\$1,055	\$ 644	\$1,282	\$ 767	\$ 707	\$ 591
Expenses:						
Depreciation	263	254	204	117	112	83
Operating Expenses	174	110	125	100	77	78
Overhead	20	20	25	11	11	7
Interest	32	32	33	20	21	20
Royalty	113	69	137	82	76	63
Severance Taxes	85	52	103	62	57	48
Property Taxes	44	41	35	20	17	14
State Income Taxes	10	2	19	11	10	8
Federal Income Taxes	105	0	247	91	102	104
Profit	\$ 207	\$ 65	\$ 351	\$ 254	\$ 222	\$ 165
Profit per barrel:	\$2.31	\$.79	\$5.04	\$6.28	\$6.37	\$5.80

Combining the data for the six years of Kuparuk production gives overall Kuparuk profit as shown in Table III-4. State royalty was computed for Kuparuk in the same manner as for Prudhoe Bay.

Table III-4
Total Kuparuk Production Profit
1982 through 1987
 (billions of dollars)

Production Revenue	\$ 5.1
Less Expenses:	
Depreciation	1.0
Operating Expenses	.7
Overhead	.1
Interest	.2
Royalty	.5
Severance Taxes	.4
Property Taxes	.2
State Income Taxes	.1
Federal Income Taxes	.6
Profit	\$ 1.3 Billion
Profit per barrel:	\$3.66

RTSXMB 519750

Oil industry profit from production activities in Alaska are shown on a year-by-year basis in Table III-5.

Table III-5
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1983 - 1987:

	1987	1986	1985	1984	1983
Production Revenue	\$8,046	\$5,367	\$11,735	\$11,592	\$11,564
Depreciation	1,394	1,418	1,123	866	779
Operating Expenses	940	653	679	678	500
Exploration Expenses	288	288	514	258	818
Overhead	139	133	173	106	111
Interest	192	183	183	148	150
Royalty	970	647	1,414	1,397	1,393
Severance Taxes	871	623	1,403	1,395	1,388
Property Taxes	197	192	188	172	159
State Income Tax	92	37	182	189	174
Windfall Profit Tax			39	235	475
Federal Income Tax	<u>1,007</u>	<u>0</u>	<u>2,424</u>	<u>1,627</u>	<u>1,774</u>
Profit	<u>\$1.956</u>	<u>\$1.192</u>	<u>\$3.413</u>	<u>\$4.521</u>	<u>\$3.841</u>
Profit per barrel:	<u>\$3.18</u>	<u>\$2.01</u>	<u>\$5.83</u>	<u>\$8.15</u>	<u>\$6.97</u>

1978 - 1982:

	1982	1981	1980	1979	1978
Revenue	\$12,785	\$14,484	\$9,961	\$6,321	\$2,254
Expenses:					
Depreciation	698	540	504	345	280
Operating Expenses	506	571	183	188	176
Exploration Expenses	647	419	176	174	274
Overhead	91	55	16	2	a
Interest	171	18	10	167	247
Royalty	1,641	1,745	1,198	762	272
Severance Taxes	1,536	1,291	923	622	195
Property Taxes	165	151	152	130	113
State Income Tax	175	702	556	369	66
Windfall Profit Tax	1,491	3,314	861		
Federal Income Tax	<u>2,212</u>	<u>2,067</u>	<u>2,110</u>	<u>399</u>	<u>8</u>
Profit	<u>\$3.452</u>	<u>\$3.610</u>	<u>\$3.270</u>	<u>\$3,161</u>	<u>\$ 623</u>
Profit per barrel:	<u>\$6.33</u>	<u>\$6.96</u>	<u>\$6.21</u>	<u>\$6.97</u>	<u>\$1.56</u>

Table III-5 (continued)
Total Alaska Production Profit
1969 through 1987
(millions of dollars)

1973 - 1977:

	1977	1976	1975	1974	1973
Revenue	\$ 1,054	\$ 380	\$ 396	\$ 372	\$ 377
Expenses:					
Depreciation	53	16	16	16	16
Operating Expenses	64	16	15	10	3
Exploration Expenses	25	25	25	25	25
Overhead	3	a	a	a	a
Interest	177	1	1	a	a
Royalty	131	46	48	45	45
Severance Taxes	76	28	27	15	15
Property Taxes	31	12	13	13	13
State Income Tax	49	23	24	24	24
Federal Income Tax	<u>52</u>	<u>85</u>	<u>91</u>	<u>89</u>	<u>89</u>
Profit	<u>\$ 394</u>	<u>\$ 133</u>	<u>\$ 142</u>	<u>\$ 140</u>	<u>\$ 140</u>
Profit per barrel:	<u>\$2.49</u>	<u>\$1.94</u>	<u>\$1.94</u>	<u>\$1.89</u>	<u>\$1.33</u>

1969 - 1972:

	1972	1971	1970	1969
Revenue	\$ 283	\$ 279	\$ 278	\$ 227
Expenses:				
Depreciation	16	16	17	14
Operating Expenses	3	2	1	1
Exploration Expenses	25	25	25	25
Overhead	a	a	a	a
Interest	a	a	a	a
Royalty	34	34	34	27
Severance Taxes	12	11	8	6
Property Taxes	13	10	14	13
State Income Tax	17	17	17	13
Federal Income Tax	<u>63</u>	<u>63</u>	<u>64</u>	<u>50</u>
Profit	<u>\$ 99</u>	<u>\$ 98</u>	<u>\$ 100</u>	<u>\$ 79</u>
Profit per barrel:	<u>\$1.23</u>	<u>\$1.22</u>	<u>\$1.17</u>	<u>\$1.04</u>

a. Less than \$1 million

RTSXMB 519752

Total industry profit from production for the years 1969 through 1987 are shown in Table III-6, below. State royalty was computed in the same manner as for the Prudhoe Bay field.

Table III-6
Total Alaska Production Profit
1969 through 1987
(billions of dollars)

Production Revenue	\$ 97.6
Less Expenses:	
Depreciation	8.1
Operating Expenses	5.3
Exploration Expenses	4.1
Overhead	.8
Interest	1.7
Royalty	11.8
Severance Taxes	10.4
Property Taxes	1.8
State Income Taxes	2.7
Windfall Profit Tax	6.4
Federal Income Taxes	<u>14.3</u>
Profit	<u>\$ 30.2 Billion</u>

Profit per barrel: \$4.96

As stated throughout the report, this is the best estimate available of Alaska oil industry production profit. There are, however, some questions concerning the profit numbers which are necessary to understand the possible range within which the actual profit number might fall.

Revenue Issues. As noted in Section I, revenues have been estimated based on a weighted average of all producers. The resulting revenue amount is 1.19% greater than that which would be obtained using Sohio's data alone. The question is what effect would using estimated realizations have on the reported profit numbers. Over the production history of the Alaska North Slope, approximately 50% of ANS crude was sold on the U.S. West Coast where net realizations are approximately \$1.40 greater than sales on the Gulf Coast

(Barclay's, 1988, p. 3). West Coast sales have been made almost entirely by producers other than Sohio. Under this assumption, revenues would increase by \$1.8 billion with a resulting increase in after-tax profit of \$ 1.0 billion. This was determined by taking the estimated average realization of \$17.68 for Sohio and adding the extra value of West Coast sales for 50% of production. This step indicates that this approach would yield an additional average realization of \$.37 per barrel over all 4.8 billion barrels of working interest production.

A second issue related to revenues is the 1986 Arco severance tax settlement. Arco paid \$243 million in this settlement. Assuming that Arco's annual report data were based on its original pricing methodology, and that the severance tax rate was 15%, this would imply that the Arco revenue data which was used in this analysis understated revenues by \$1.6 billion. After allowing for 15% severance tax, 3% Alaska income tax and 34% effective Federal income tax, the net profit effect is a \$.8 billion increase. Part of the settlement may have been interest, but it is also likely that the settlement rate was less than 15%. If the net effect of these two factors is to offset each other, as expected, the profit increase suggested here is supported.

An additional revenue issue is the 1988 \$171 million settlement on income taxes by Arco. The extent to which this settlement affected revenues and expenses is not public information. Presumably there would be an addition to the relevant items in the Arco income statements if those statements had been prepared on the basis which Arco used for its Alaska income tax. To the extent that the financial statements relied on here are the same as that used in the tax return, profit would be understated.

RTSXMB 519754

It should be noted with respect to both of these settlements with Arco that they are not final settlements. The outcome of ongoing litigation and its effect on profit estimates cannot be ascertained at this time.

Depreciation Expense. For the Prudhoe Bay field, the per barrel depreciation estimates used amounted to \$2.15 in 1987, \$2.25 in 1986 and \$1.75 in 1985. *Petroleum Intelligence Weekly* (February 1, 1988) estimates Prudhoe Bay depreciation at \$2.25, \$2.17 and \$1.53 for those years, respectively. On average for those years, this suggests that the depreciation estimates reported here may be too high by approximately \$.07 per barrel. If this is the case, depreciation for Prudhoe Bay may be overstated by \$336 million over the eleven-year production history. After a 3% Alaska income tax and a 34% estimated Federal income tax, this would imply that profit is understated by \$217 million.

As noted in Section II, other sources have estimated Kuparuk depreciation at up to \$3.80 per barrel, which is \$.89 per barrel more than the average estimate included in this report. If these other estimates are correct, this would imply that Kuparuk depreciation needs to be increased by \$307 million. This would decrease Kuparuk after-tax profit by approximately \$198 million.

Operating Costs. This report indicates that operating costs, including property taxes were \$1.08 per barrel over the life of Prudhoe Bay field. *International Petroleum Finance* estimates these costs at \$.91 per barrel. *Petroleum Intelligence Weekly* estimates the costs at approximately \$1.03 per barrel. This suggests that the estimate in this report may be between \$.05 and \$.17 per barrel greater than other estimates. At \$.05 per barrel, after-tax profit would increase by \$153 million and at \$.17 the effect would be a \$522 million increase in profit.

Windfall Profit Taxes. Based on Arco's estimates, total Prudhoe Bay windfall profit tax would equal \$4.6 billion. Using the U.S. Internal Revenue Service data, windfall profit tax collections for the ANS totalled \$5.9 billion. The latter number was used even though the net income limitation provisions of the tax act may have served to reduce the expense. On the other hand, the data reported by Arco would have been before any settlement of audit differences. The indicated range for windfall profit tax expense is, therefore, \$1.3 billion before tax and an estimated \$.8 billion after tax, subject to possible adjustments as a result of settlements. Profit reported here may, therefore, be too low by up to \$.8 billion.

Overhead. As noted in Section II, overhead included in this report was estimated at \$.8 billion for the period of Prudhoe Bay production. Had a weighted average based on Arco's and Sohio's data been used in a two-factor allocation, overhead would have increased by \$.4 billion, which translates into an approximately \$.3 billion after tax decrease in profit compared to the amounts reported here.

On the other hand, using a three-factor formula for estimating overhead based on the Arco/Sohio composite results in overhead of \$.4 billion, which is \$.4 billion less than the amount used in this report. This would imply that profit had been understated by \$.3 billion after tax.

Interest Expense. Analysis of the interest costs of Arco and Sohio suggests that the differences attributable to this factor amount to less than \$50 million. Since adequate data are not available and since the amount is low relative to the total profit, this analysis has not been pursued further.

Federal Income Taxes. The estimated effective tax rate for Alaska oil production for this report is 32.1%. This is equal to the \$14.2 billion in income taxes divided by pre-tax income of \$44.3 billion. If the Federal income taxes had

been based on the estimated 29% effective tax rate for the industry, income taxes would have decreased by \$1.0 billion, with a corresponding decrease in reported profit to producers.

Using the effective tax rates for the primary Alaska oil producers given in Table II-16, the unweighted average current effective tax rate is 26.3% for 1978 to 1985. The rate is negative in 1986. Had the Federal income taxes in this report been based on the average effective rate for the producers over this eight-year period, the amount would have been \$11.5 billion, which is \$2.7 billion less than that included in this report. This amount would pass directly through as an increase in profit of \$2.7 billion.

Summary. The questions raised in this section cannot be resolved without additional data. For this reason, the effect of the different assumptions on profit are summarized so that one can adjust the results according to their own interpretation of the data. The effect of each assumption is given in Table III-7.

Table III-7
Effect of Assumptions on Profit
(billions of dollars)

Item	Increase in Profit	Decrease in Profit
Use of West Coast prices	\$ 1.0	
Arco severance tax settlement	.8	
Outside Prudhoe depreciation estimates	.2	
Outside Kuparuk depreciation estimates		\$.3
Use of <i>Petroleum Intelligence</i> Weekly operating costs	.2	
Use of <i>Petroleum Finance</i> operating costs	.5	
Use of Arco windfall profit tax data	.8	
Composite two-factor overhead		.3
Three-factor overhead	.3	
39% Federal tax rate	1.0	
Composite company rate	<u>2.7</u>	
Total increases	<u>\$ 7.5</u>	
Total decreases		<u>\$ 0.6</u>

RTSXMB 519757

T-63

A review of these alternative estimates indicates that the profit reported here is within a reasonable range of actual profit and is probably on the conservative side.

Confidential Pursuant to
APUC Order P-97-4(22)

RTSXMB 519758

T-33000189

IV. TAPS PROFIT

GENERAL METHODOLOGY

A review of data sources on the Trans Alaska Pipeline System indicates that the annual reports filed by Sohio Pipeline Company reflect quite closely a .3334 interest in pipeline revenues and expenses. This occurs in part because nearly 100% of Sohio Pipeline Company's activities are related to TAPS. Effective tax rates were used to estimate Federal income taxes for the reasons stated above. Sohio Pipeline Company reports were available for 1978 through 1987. Due to the short production period in 1977, the pipeline probably broke even or had such a small profit or loss that it would not affect the results.¹⁸ For 1985 through 1987, Sohio Pipeline Company provided a separate statement of TAPS revenues, costs and profit. Most of the costs were incurred jointly through Alyeska and, thus, would be shared by all pipeline owners *pro rata*. The remaining expenses appear quite close to those indicated by other observers as appropriate for TAPS in total. Operating data in Table IV-1 represent the information reported in the Sohio Pipeline Company annual reports divided by .3334. Alaska income tax estimates were based on an effective rate of 9.4% during 1978 to 1981 and an effective rate of 3% thereafter. The Federal rate was estimated in the same manner as for production.

The amounts reported in Table IV-1 were compared to other sources. Property taxes were compared to the Alaska Department of Revenue's *Revenue Sources* reference. The amounts are quite similar.

¹⁸1977 throughput would have been approximately 28% of 1978 throughput. This would imply revenues of \$690 million. Operating and administrative expenses are estimated at one-half of 1978. Depreciation would probably have been proportional to throughput. Property taxes would have been the same as in 1978. Interest expense would be approximately \$236 million for an estimated before-tax loss of \$20 million, which is not significant relative to other revenues and expenses.

Table IV-1
TAPS Profit Projected from Sohio Pipeline Co.
(millions of dollars)

1983 through 1987:					
	1987	1986	1985	1984	1983
Revenues	\$2,765	\$3,080	\$3,578	\$3,926	\$3,899
Expenses:					
Operating and Administrative	255	343	247	387	483
Depreciation	351	364	363	507	558
Property Taxes	147	164	168	171	165
Interest	150	440	411	570	579
Alaska Income Taxes	56	53	72	69	63
Federal Income Taxes	<u>633</u>	<u>0</u>	<u>993</u>	<u>609</u>	<u>669</u>
Profit	<u>\$1.174</u>	<u>\$1,716</u>	<u>\$1,325</u>	<u>\$1,614</u>	<u>\$1,382</u>
1978 to 1982:					
	1982	1981	1980	1979	1978
Revenues	\$3,896	\$3,605	\$3,554	\$2,963	\$2,394
Expenses:					
Operating and Administrative	498	474	435	330	381
Depreciation	549	507	591	495	417
Property Taxes	168	171	168	174	174
Interest	648	681	720	771	846
Alaska Income Taxes	61	167	154	112	54
Federal Income Taxes	<u>795</u>	<u>645</u>	<u>645</u>	<u>102</u>	<u>9</u>
Profit	<u>\$1,178</u>	<u>\$ 961</u>	<u>\$ 842</u>	<u>\$ 980</u>	<u>\$ 513</u>

Arco reported TAPS depreciation in its 10-K's for 1981 through 1987. The amounts were factored to reflect 100% depreciation for TAPS as shown in Table IV-2. The amounts for depreciation obtained in this manner were 38% lower than the amounts obtained from the Sohio analysis. Over the life of TAPS, the depreciation estimate is based on a weighted average of the Sohio and Arco depreciation data. The weighted average is based on Arco's 22% interest in TAPS and Sohio's 33% interest. The method assumes that the missing data are equivalent to the weighted average of the data that are available. The resulting depreciation expense number is \$700 million lower than it would have been using the Sohio data alone.

Table IV-2
Arco-based TAPS Depreciation Estimates
(millions of dollars)

<i>Year</i>	<i>Arco 10-K</i>	<i>Estimated Total</i>
1987	\$ 60.0	\$ 272.3
1986	60.0	272.3
1985	60.0	272.3
1984	60.0	272.3
1983	58.9	267.7
1982	57.3	260.5
1981	80.4	365.5

Reducing the depreciation estimate increases taxable profit and income taxes. Alaska income tax was increased by \$34 million based over the life of TAPS. Federal income tax was increased by \$204 million over the same period. Apportioning the depreciation adjustment over the life of TAPS to date results in the schedule of TAPS profit shown in Table IV-3.

Table IV-3
TAPS Profit
(millions of dollars)

1983 through 1987:

	<i>1987</i>	<i>1986</i>	<i>1985</i>	<i>1984</i>	<i>1983</i>
Revenues	\$2,765	\$3,080	\$3,578	\$3,926	\$3,899
Expenses:					
Operating and Administrative	255	343	247	387	483
Depreciation	299	310	309	431	475
Property Taxes	147	164	168	171	165
Interest	150	440	411	570	579
Alaska Income Taxes	57	55	73	71	66
Federal Income Taxes	<u>631</u>	<u>0</u>	<u>984</u>	<u>610</u>	<u>674</u>
Net Profit	<u>\$1,226</u>	<u>\$1,768</u>	<u>\$1,386</u>	<u>\$1,686</u>	<u>\$1,457</u>
Profit per barrel:	<u>\$2.08</u>	<u>\$3.07</u>	<u>\$2.44</u>	<u>\$3.17</u>	<u>\$2.77</u>

Table IV-3 (continued)
TAPS Profit
(millions of dollars)

1978 to 1982:	1982	1981	1980	1979	1978
Revenues	\$3,896	\$3,605	\$3,554	\$2,963	\$2,394
Expenses:					
Operating and Administrative	498	474	435	330	381
Depreciation	467	431	503	421	355
Property Taxes	168	171	168	174	174
Interest	648	681	720	771	846
Alaska Income Taxes	63	203	162	119	60
Federal Income Taxes	802	599	617	129	8
Net Profit	<u>\$1,250</u>	<u>\$1,046</u>	<u>\$ 949</u>	<u>\$1,019</u>	<u>\$ 570</u>
Profit per barrel	<u>\$2.42</u>	<u>\$2.15</u>	<u>\$1.95</u>	<u>\$2.49</u>	<u>\$1.64</u>

Estimates of revenues and expenses included in this report were compared to information provided in connection with the TAPS settlement methodology. It appears from comparison with the data available to us that the revenue estimates here are approximately \$400 million greater than indicated by the TAPS settlement data. The alternate estimates of operating and administrative expenses for 1978 to 1984 are within approximately \$50 million. The estimates of Federal income taxes are lower in this report because the other sources used the statutory rate for tax expense purposes. Since the long-run relationship between before-tax profit and tax expense shows that the statutory rate overstates actual tax outlays, the effective rate is used in this income computations.

TAPS settlement data from Deloitte Haskins and Sells indicate that operating expenses average \$.58 per barrel. The estimate in this report is \$.64 per barrel. The Deloitte Haskins and Sells data indicate depreciation of \$.59 per barrel. Before the Arco adjustment, the estimate in this report was \$.80 per barrel. After the Arco adjustment, the estimate here is \$.68 per barrel. The Federal income

tax allowance indicated from the Deloitte Haskins and Sells (DH&S) analysis of TAPS costs is \$.75 per barrel. The estimate in this report is \$.86 per barrel. The expense estimates used in the profit estimates reported here are consistently higher than those indicated by DH&S. Thus, profit reported here is lower than would be indicated using the DH&S data.

Barclay's de Zoete Wedd (1988) estimate cash costs of \$.65 per barrel for TAPS. This would include operating and administrative costs plus property taxes. The estimate of these costs in this report is \$.92 per barrel. Barclay's de Zoete Wedd estimates depreciation at \$.80 per barrel, which is the same as used here after accounting for the Arco adjustment.

Petroleum Intelligence Weekly estimated that pipeline profit was \$2.18 per barrel in 1985, \$.64 per barrel in 1986 and \$.53 per barrel in 1987. The estimates used in this report are \$.75, \$.94 and \$.60 for each of those years respectively. Over the three-year period, they estimate a total profit of \$6.1 billion. The profit reported here is \$4.2 billion before the depreciation adjustment.

For the years 1983 through 1987, Arco reported the net income after tax of Arco Pipeline Inc., which holds Arco's interest in TAPS. Assuming that all of the income of Arco Pipeline is related to TAPS (which appears to be the case),¹⁹ TAPS income for each of these years projected from the Arco Pipeline data would be \$1.3 billion, \$1.3 billion, \$1.5 billion, \$1.4 billion and \$1.4 billion for a total over the five-year period of \$6.9 billion. The estimate based on Sohio data is \$7.2 billion. A weighted average estimate of profit based on 21.4% Arco ownership and 33.34% Sohio ownership gives a profit estimate for the four-year period for which both data series are available of \$7.1 billion, which is within 2% of the estimate reported here.

¹⁹TAPS income so completely dwarfs income from other pipelines that substantially all the income is attributable to TAPS.

Each of the sources which has looked into TAPS revenues, profit and costs has developed varying profit estimates. It appears that the adjusted profit indicated in Table IV-3 represent a "middle-of-the-road" estimate. Over the period of TAPS operation, estimated total profit is as follows in Table IV-4:

Table IV-4
Total Estimated TAPS Profit
(billions of dollars)

Revenues	\$ 33.7
Expenses:	
Depreciation	4.0
Operating and Administrative	3.8
Interest	5.8
Property Taxes	1.7
Alaska Income Tax	.9
Federal Income Tax	<u>5.1</u>
Profit	<u>\$12.4 Billion</u>

V. OTHER INFORMATION

Downstream Profit. The profit data which have been developed in this report do not include any profits earned beyond Valdez. It has been reported elsewhere that producers may earn between \$.25 and \$1.00 per barrel in profits on tanker and trans-Panama canal shipping operations. These profits serve to reduce the net cost of Alaska oil landed on the U.S. West and Gulf Coasts.

There is some evidence that U.S. West Coast prices are lower because of Alaska oil production than they would be without Alaska production. This occurs because prices of crude oil on the U.S. West Coast tend to average \$1.00 per barrel less than prices on the U.S. Gulf Coast. If imported crude oil had to be substituted for Alaska crude on the U.S. West Coast, prices there would be at least equal to prices on the U.S. Gulf Coast. Indeed, a substantial argument can be made that prices on the U.S. West Coast would be greater than Gulf Coast prices because shipping costs for imported crude oil would be greater f.o.b. the West Coast than the Gulf Coast. Thus, there can be additional refining profits from Alaska crude which have not been included in this analysis.

These downstream profit issues are beyond the scope of this project. They do indicate, however, that the producer's economic benefits of Alaska oil production extend beyond the profit obtained within the boundaries of the State of Alaska.

Shares. The revenues from Alaska oil and gas production and transportation go to pay for costs incurred in those activities, state taxes and royalties, federal taxes and profit to the producers. The shares of revenues received by the producers, state and federal governments are itemized in Table V-1.

Table V-1
Shares
(billions of dollars)

	<i>Producers</i>	<i>State</i>	<i>Federal Government</i>
Royalties		\$ 11.8	
Severance taxes		10.4	
Property taxes*		3.5	
Income taxes		3.6	\$ 19.4
Windfall profit taxes			6.4
Production profit	\$ 30.2		
TAPS profit	12.4		
Totals	\$ 42.6	\$ 29.3	\$ 25.8
Percentages	43.6%	30.0%	26.4%

* Includes local property taxes.

Profit as an Hourly Rate. Forty-two billion dollars is a significant number and one that is difficult to put in perspective. Relating the number to an hourly rate over 10.5 years of production (91,980 hours at 24 hours per day, 365 days per year) gives a rate of \$463,144 profit received after tax.

Return on Investment. It is also possible to relate profit received by Alaska producers to the investment made in TAPS and production activities. This analysis is referred to as return on investment. The analysis compares cash flows to investments.

Investment in TAPS was an estimated \$9,400 million in 1975 to 1977. The initial investment in Prudhoe Bay was an estimated \$3,700 million.²⁰ Over time, this investment was increased as a result of infield drilling, the waterflood project and the gas miscible fluid project. The estimated total accumulated investment in Prudhoe Bay is \$8,700 million. As of 1987, the investment in Kuparuk is estimated to total \$4.3 billion. This includes a portion of the waterflood project which was being installed in 1987 - 1988. The investment in Milne Point was

²⁰Some of these expenditures were made as early as 1969. However, more precise dates are not available for these outlays. If the \$900 million in 1969 lease bonuses is accounted for as a 1969 outlay, the rate of return (assuming no debt) drops to 28.1%. Alternatively, this analysis placed no value on the ANS properties for cash flows received after 1987. Assuming that these cash flows are worth \$10 billion, the rate of return (assuming no debt) increases to 31.1%. Similar adjustments would be required to the returns assuming debt.

\$575 million. Lisburne had an estimated investment cost of \$1,000 million and Endicott an estimated project cost of \$1,000 million. A summary of the estimated investments in the ANS is given in Table V-2. These amounts are based on estimates in Arco's and Sohio's annual reports and compared to other estimates.

Table V-2
Investment Schedule
(millions of dollars)

<i>Year</i>	<i>Prudhoe</i>	<i>TAPS</i>	<i>Other ANS</i>	<i>Total</i>
1987	\$ 720		\$1,900	\$2,620
1986			1,000	1,000
1985	720			720
1984			570	570
1983	2,000			2,000
1982				0
1981	1,100		3,400	4,500
1980	250			250
1979	250			250
1978				0
1977	1,850	4,700		6,550
1976	1,850	4,700		6,550

Assuming 100% equity investment, cash returns on these investments would be equal to the reported profit numbers plus depreciation and interest. This is based on the fact that if one invested 100% equity, one would incur no interest costs. Column 1 of Table V-3 shows the production profit from Table III-5. Column 2 of Table V-3 is the depreciation on production. Column 3 is the sum of profit plus depreciation. Column 4 is the interest costs. Adding the profit plus depreciation from column 3 and the interest from column 4 gives the "all-equity cash flows" from production shown in column 5 of Table V-3.

The same process was followed for TAPS which yields the data in the fifth column of Table V-4.

RTSXMB 519767

Table V-3
Production Cash Flows
(millions of dollars)

<i>Year</i>	<i>Profit</i>	<i>Depreciation</i>	<i>Profit plus Deprec.</i>	<i>Interest</i>	<i>Profit, Interest Deprec. & Explor.</i>	<i>Exploration</i>	<i>Profit, Deprec. & Explor.</i>
1987	\$1,956	\$1,394	\$3,350	\$192	\$3,542	\$288	3,638
1986	1,192	1,418	2,610	183	2,793	288	2,898
1985	3,413	1,123	4,536	183	4,719	514	5,050
1984	4,498	866	5,364	148	5,512	258	5,622
1983	3,841	779	4,620	150	4,770	818	5,438
1982	3,452	698	4,150	171	4,321	647	4,797
1981	3,610	540	4,150	18	4,168	419	4,569
1980	3,250	504	3,754	10	3,764	176	3,930
1979	3,161	345	3,506	167	3,673	174	3,680
1978	623	280	903	248	1,151	274	1,177
1977	425	53	478	177	655	25	503

Table V-4
TAPS Cash Flows
(millions of dollars)

<i>Year</i>	<i>Profit</i>	<i>Depreciation</i>	<i>Profit & Deprec.</i>	<i>Interest</i>	<i>Profit, Interest Deprec. & Explor.</i>
1987	\$1,226	\$ 299	\$1,525	\$ 150	\$1,675
1986	1,768	310	2,078	440	2,518
1985	1,386	309	1,695	411	2,106
1984	1,686	431	2,117	570	2,687
1983	1,457	475	1,932	579	2,511
1982	1,250	467	1,717	648	2,365
1981	1,046	431	1,477	681	2,158
1980	949	503	1,452	720	2,172
1979	1,019	421	1,440	771	2,211
1978	570	355	925	846	1,771

The total all-equity cash flows are shown in Table V-5. The first column is the investment flow from Table V-2. The second column is the production cash flow plus interest and depreciation from Table V-3. The third column is the TAPS cash flow plus interest and depreciation from Table V-4. The last column is the sum of the production and TAPS cash flows minus the investment flows.

Table V-5
All-equity Cash Flows
(millions of dollars)

Year	Investment	--Cash Flows--Net		Cash Flow
		Production	TAPS	
1987	\$2,620	\$3,542	\$1,675	\$2,597
1986	1,000	2,793	2,518	4,311
1985	720	4,719	2,106	6,105
1984	570	5,512	2,687	7,629
1983	2,000	4,770	2,511	5,281
1982	0	4,321	2,365	6,686
1981	4,500	4,168	2,158	1,826
1980	250	3,764	2,172	5,686
1979	250	3,673	2,211	5,634
1978	0	1,151	1,771	2,922
1977	6,550	655	0	-5,895
1976	6,550	0	0	-6,550

The equivalent rate of return earned on this stream of cash flows after tax is 29.7%.

According to the Sohio annual report of 1978, approximately 75% of the investment was financed with debt. In this case, the investments in 1976 and 1977 as shown in Table V-2 would be \$1,638 million net each year. This is 25% of the investment outflows in those years. The remainder would have been financed with debt. Interest expense would be incurred on this debt and the debt would have to be repaid. The cash flow data from columns 3 of Tables V-3 and V-4 is the profit plus depreciation. These cash flows include a deduction for interest expense. These cash flow numbers are shown in column 2 and 3 of Table V-6. Assuming that all of the cash flows were used to pay off the debt as quickly as possible, the loan repayment would have consumed all of the cash flows in 1978 through 1979 and all but \$2,131 million in 1980. The net cash flows in each year are shown in column 4 of Table V-6.

RTSXMB 519769

Table V-6
Cash Flows with 25% Equity
(millions of dollars)

	<i>Investment</i>	<i>—Cash Flow—</i>		<i>Net Cash Flow</i>
		<i>Production</i>	<i>TAPS</i>	
1987	\$2,620	\$3,350	\$1,525	\$2,255
1986	1,000	2,610	2,078	3,688
1985	720	4,536	1,695	5,511
1984	570	5,364	2,117	6,911
1983	2,000	4,620	1,932	4,552
1982	0	4,150	1,717	5,867
1981	4,500	4,150	1,477	1,127
1980	250	3,754	1,452	2,131
1979	250	3,506	1,440	0
1978	0	903	925	0
1977	6,550	478	0	-1,160
1976	6,550	0	0	-1,637

The rate of return implied from the stream of cash flows shown in Table V-6 is 43.7%.

REINVESTMENT RATIOS

A question of interest is the extent to which cash flows from Alaska oil and gas operations are reinvested in Alaska. Reinvestment is defined as investments in ANS projects subsequent to the initial investment in Prudhoe Bay and TAPS plus exploration costs. These amounts are shown in column 1 of Table V-7. The relevant cash flows for reinvestment analysis are the production cash flows plus exploration costs and the cash flows from TAPS. Interest costs are deducted in determining these cash flows. The production amounts are shown in the last column of Table V-3. The production cash flows are shown in column 2 of Table V-7 and the TAPS cash flows are shown in column 3 of Table V-7. The total cash flows are shown in column 4 of Table V-7. The last column of Table V-7 is the ratio of reinvestment to the cash flows.

Table V-7
Reinvestment Ratios
 (millions of dollars)

Year	Re- investment	---Cash Flows---			Reinvestment Ratio
		Production	TAPS	Total	
1987	\$2,908	\$3,638	\$1,525	\$5,163	56.32%
1986	1,288	2,898	2,078	4,976	25.88%
1985	1,234	5,050	1,695	6,745	18.30%
1984	828	5,622	2,117	7,739	10.70%
1983	2,818	5,438	1,932	7,370	38.24%
1982	647	4,797	1,717	6,514	9.93%
1981	4,919	4,569	1,477	6,046	81.36%
1980	426	3,930	1,452	5,382	7.92%
1979	424	3,680	1,440	5,120	8.28%
1978	274	1,177	925	2,102	13.04%
Totals	<u>\$15,766</u>			<u>\$57,157</u>	

The data from Table V-7 indicate that the ANS producers are reinvesting approximately 27.8% of their cash flows in Alaska.

RTSXMB 519771

Appendix A Sohio's 1982 Annual Report Disclosure

Supplementary Information on Oil and Gas Exploration, Development and Production Activities

This section provides information required by Statement of Financial Accounting Standards No. 89 (FASB 89), "Disclosures about Oil and Gas Producing Activities," which was issued in November 1982. FASB 89 aims to establish a comprehensive set of disclosures for oil and gas producing activities that replaces disclosures formerly required by either the Financial Accounting Standards Board (FASB) or the Securities and Exchange Commission (SEC), or both.

Three general disclosure areas comprise the information in this section. The first area provides historical information about costs and revenues, including the Company's aggregate recorded investment in oil and gas properties, annual

costs incurred and a separate statement of the results of operations for producing activities. The second area contains the Company's petroleum engineers' quantity estimates for proved oil and gas reserves and the major factors causing changes in these reserves estimates. The first area of disclosure represents our compliance with the FASB's requirement to assign a monetary value to proved reserve quantities and changes therein using a standardized formula.

The Company has provided additional commentary throughout this section that is important for a proper understanding of the nature of the data provided and its inherent limitations.

Historical Information

Millions of Dollars	1982			1981			1980		
	Total	At-risk	48 States	Total	At-risk	48 States	Total	At-risk	48 States
Costs Incurred									
Completed Costs as of December 31									
Proved properties	64,310	64,100	61,887	63,848	63,387	1,481	62,856	62,856	62,811
Unproved properties	1,388	888	788	878	128	888	488	488	488
	65,698	64,988	62,675	64,726	63,515	2,369	63,344	63,344	63,299
Reserve quantities									
Proved reserves	1,777	1,388	888	1,328	888	388	888	717	388
Unproved reserves	64,781	63,600	61,787	63,498	62,429	1,781	62,456	61,889	61,421
Costs Incurred (development or otherwise)									
Acquisition of properties	0	0	0	0	0	0	0	0	0
Exploration	418	88	388	383	88	388	148	38	148
Development	1,148	888	888	888	888	888	388	388	388

Results of Operations for Producing Activities

The following summarizes the "Results of Operations for Producing Activities," as defined by FASB 89, for the years ended December 31, 1982, 1981 and 1980. As required, financing costs are not included in this statement. Income

taxes are included in the results, but were computed under FASB guidelines using statutory tax rates, while considering the effects of permanent differences and tax credits relating to oil and gas producing activities.

Millions of Dollars	1982			1981			1980		
	Total	At-risk	48 States	Total	At-risk	48 States	Total	At-risk	48 States
Revenues									
Production sales	1,881	1,888	118	2,878	2,888	128	1,247	1,181	88
Commodity derivatives	388	878	48	288	272	17	288	278	18
Other revenues	188	88	88	107	72	88	37	2	38
Adjusted cost of unproved properties	188	7	188	78	8	78	88	18	38
Loss from sales	88	8	88	124	18	188	48	13	21
Other	188	18	88	83	4	88	31	8	21
	488	87	481	373	48	324	178	38	178
Income before interest and income taxes	3,013	2,817	888	3,238	2,888	448	1,778	1,488	218
Income taxes	2,788	2,188	1,888	3,188	2,248	1,888	2,718	2,328	1,888
	2,298	1,888	1,488	1,848	1,778	1,888	1,558	1,578	1,488
	81,422	81,888	81,888	81,718	81,818	81,188	81,222	81,252	81,288

Appendix B
Barclay's de Zoete Wedd Prudhoe Bay Model (1988)

PROFITABILITY MODEL FOR PRUDHOE BAY FIELD

(\$/barrel)	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Alaskan Crude Price*	28.48	14.07	17.37	14.01	14.50	13.23	13.98	18.79	17.82	18.51	21.28
Less:											
Tanker Freight	(3.24)	(2.71)	(2.60)	(2.70)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)	(3.00)
TAPS charge	(3.31)	(4.50)	(3.93)	(3.11)	(2.60)	(2.23)	(2.23)	(2.45)	(2.55)	(2.90)	(3.13)
Pipeline Loss	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)	(0.10)
Value at Pump Station One	17.83	6.78	10.74	8.10	8.80	8.88	10.64	11.24	11.87	12.51	15.03
Severance Tax	(2.39)	(0.88)	(1.29)	(0.97)	(1.06)	(1.19)	(1.28)	(1.35)	(1.42)	(1.50)	(1.50)
Field Operating Costs	(1.00)	(0.90)	(0.90)	(0.90)	(0.95)	(0.95)	(1.00)	(1.05)	(1.10)	(1.13)	(1.20)
Field Overhead	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.23)	(0.23)	(0.23)	(0.30)	(0.30)	(0.30)
Depreciation & Depletion	(1.60)	(2.00)	(2.00)	(2.10)	(2.20)	(2.20)	(2.30)	(2.40)	(2.40)	(2.45)	(2.45)
Ad Valorem Tax	(0.30)	(0.30)	(0.30)	(0.30)	(0.31)	(0.32)	(0.34)	(0.35)	(0.36)	(0.38)	(0.38)
Pre-tax Earnings Per Barrel	12.14	2.48	6.95	3.83	4.08	4.97	5.47	5.94	6.29	6.73	6.58
Operating Profit (\$m)	3015	617	1528	934	1058	1269	1278	1257	1282	1277	1421

NOTES:

* The Alaskan crude price is a weighted average of the prices received for sales on the West and Gulf Coasts; Gulf Coast sales normally fetch around \$1/barrel more than those on the West Coast. We assume 1/3 of sales are made on the West Coast with the balance on the Gulf.

→ Tanker freight is again a weighted average of the rate for deliveries from Valdez to the West and Gulf Coasts. Because shipping costs to the Gulf Coast are normally some \$2.40/barrel higher, sales on the West Coast are more profitable to BP despite the fact that the crude oil commands a lower price than on the Gulf (see Section 3 below). In 1989 we have assumed that tanker costs rise by around \$0.50/barrel due to an increase in the use of expensive to operate Jones Act vessels (see Section 3), partly offset by a 70,000 barrel/day increase in shipments by pipeline from the West to Gulf Coasts (which is some 60¢/barrel cheaper than transport by ship via Panama).

Appendix C Salomon Brothers' Arco Alaska Profits Model (1987)

Figure 3. Atlantic Richfield Company - Actual and Projected Alaskan Production Earnings, 1986-92E
(Dollars Per Barrel Unless Otherwise Indicated)

	1986	1988	1989E	1990E	1991E	1992E	1993E	1994E
Prudhoe Bay Field								
Sale Price - West Texas Intermediate								
Crude	\$28.00	\$13.75	\$17.50	\$20.00	\$22.00	\$24.00	\$25.00	\$26.00
Prudhoe Bay Field Crude Price*	28.00	15.20	16.20	19.70	21.25	23.15	24.15	25.10
Transportation Deductions								
Value of U.S. Gulf Coast	\$4.50	\$3.80	\$3.85	\$4.10	\$4.25	\$4.40	\$4.50	\$4.60
Inter-Alaska Pipeline Charge	5.28	4.75	3.90	3.50	3.25	3.00	3.00	3.00
Equalize Prudhoe Bay Field Westward Price	\$17.02	\$6.65	\$8.15	\$11.70	\$13.75	\$15.75	\$16.65	\$17.50
Production Expenses								
Severance Tax	\$2.30	\$1.50	\$1.50	\$1.50	\$1.60	\$2.13	\$2.25	\$2.30
Workshop Price Tax	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Field Operating Expenses	0.90	0.75	0.80	0.85	0.90	0.95	0.95	1.00
Depreciation and Depletion	1.60	1.75	1.80	1.85	1.90	1.95	2.00	2.05
Unit Operating Profit	\$12.15	\$2.65	\$3.05	\$7.42	\$8.00	\$10.72	\$11.45	\$12.08
Prudhoe Net Production (MMbbl/d)	308.3	307.7	307.0	308.0	308.0	298.0	298.0	295.0
Prudhoe Operating Profit (Dollars in Millions)	\$1,388	\$297	\$368	\$834	\$1,022	\$1,118	\$1,142	\$1,081
Kuparuk River Field								
Kuparuk River Field Crude Price in U.S. Gulf	\$28.00	\$15.05	\$16.75	\$19.10	\$21.00	\$22.90	\$23.90	\$24.80
Transportation Deductions								
Value of U.S. Gulf Coast	\$4.50	\$3.80	\$3.85	\$4.10	\$4.25	\$4.40	\$4.50	\$4.60
Inter-Alaska Pipeline Charge	5.78	4.75	3.90	3.50	3.25	3.00	3.00	3.00
Kuparuk River Spout Line Charge	0.07	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Equalize Kuparuk River Westward Price	\$18.13	\$5.85	\$6.30	\$10.65	\$12.65	\$14.65	\$15.75	\$16.60
Production Expenses								
Severance Tax	\$1.30	\$0.65	\$0.65	\$0.65	\$1.05	\$1.20	\$1.25	\$1.25
Field Operating Expenses	2.50	1.85	1.65	1.60	1.85	1.90	1.95	2.00
Depreciation and Depletion	3.75	3.55	3.55	3.65	3.75	3.85	3.90	4.00
Unit Operating Profit	\$8.60	\$0.20	\$2.45	\$4.55	\$6.20	\$7.90	\$8.65	\$8.25
Kuparuk Net Production (MMbbl/d)	94.9	109.9	110.0	110.0	110.0	110.0	110.0	110.0
Kuparuk Operating Profit (Dollars in Millions)	\$238	\$8	\$268	\$183	\$246	\$317	\$347	\$321
Litwin Formation								
Litwin Formation Crude Price in U.S. Gulf		\$14.95	\$16.65	\$18.00	\$20.90	\$22.80	\$23.75	\$24.70
Transportation Deductions								
Value of U.S. Gulf Coast		\$3.80	\$3.85	\$4.10	\$4.25	\$4.40	\$4.50	\$4.60
Inter-Alaska Pipeline Charge		4.75	3.90	3.50	3.25	3.00	3.00	3.00
Equalize Litwin Westward Price		\$6.40	\$6.90	\$11.40	\$13.40	\$15.40	\$16.25	\$17.10
Production Expenses								
Severance Tax		\$0.64	\$0.60	\$1.15	\$1.35	\$1.55	\$1.65	\$1.70
Field Operating Expenses		2.70	2.75	2.75	2.85	2.90	3.00	3.10
Depreciation and Depletion		4.00	4.00	4.00	4.00	4.00	4.00	4.00
Unit Operating Profit		\$2.96	\$1.75	\$1.50	\$2.20	\$4.96	\$5.60	\$6.20
Litwin Net Production (MMbbl/d)		4.1	19.0	20.0	20.0	25.0	40.0	40.0
Litwin Operating Profit (Dollars in Millions)		\$124	\$141	\$111	\$138	\$628	\$868	\$988
Total Alaskan Operating Profit Before								
Excursion Expenses (Dollars in Millions)	\$1,000	\$380	\$600	\$1,020	\$1,300	\$1,400	\$1,541	\$1,544
MMbbl/d Net Alaskan Crude Oil Production (MMbbl/d)	403.4	421.3	427.0	438.0	448.0	433.0	448.0	445.0

* Midrange prices at Prudhoe Bay, Kuparuk River and Litwin field are extrapolated from the historical prices of West Texas Intermediate crude oil based on the historical relationship of those crude prices to the WTI crude price.
 † Litwin production begins in the fourth quarter of 1988.
 ‡ Midrange prices are per day. \$/Bbl.

Appendix D

Alaska Oil Industry Development Time Line

- 1954 - BLM issues 272 oil and gas leases.
- 1957 - Swanson River oil discovered.
- 1962 - Cook Inlet oil discovered (Middle Ground Shoals)
- 1965 - Three additional Cook Inlet oil fields discovered (Granite Point, McArthur River, Trading Bay)
- 1967 - Prudhoe Bay oil is discovered. With over 10 billion barrels of reserves, it is a "super-giant" and the largest oil field in North America.
 - Middle Ground Shoals, Granite Point and Trading Bay begin production.
- 1969 - Prudhoe Bay lease sale.
 - Kuparuk River oil discovered. With a billion barrels of reserves it is a "giant" and is second only to Prudhoe Bay as the most productive field in the United States and Canada.
- 1977 - Prudhoe Bay oil Begins flowing to Valdez through Trans-Alaska Pipeline System (TAPS).
- 1978 - Endicott oil discovered.
- 1985 - Milne Point begins production.
- 1986 - Lisburne begins production.
 - Kuparuk production peaks at 300,000 barrels per day.
- 1987 - Endicott begins production.
 - Milne Point shuts down.

Appendix E

**Total ANS Production and TAPS Profits
1977 through 1987
(millions of dollars)**

1982 - 1987

	<i>1987</i>	<i>1986</i>	<i>1985</i>	<i>1984</i>	<i>1983</i>	<i>1982</i>
Revenue	10393	8051	14707	14790	14685	15758
Expenses:						
Depreciation	1636	1674	1386	1258	1219	1131
Operating Expenses	1169	967	907	1065	954	1080
Overhead	129	124	164	100	104	84
Interest	328	611	585	709	719	807
Royalty	900	587	1316	1291	1283	1413
Severance Taxes	872	623	1403	1395	1388	1536
Property Taxes	341	353	353	339	329	329
State Income Taxes	150	94	257	253	248	239
Windfall Profit Taxes			39	211	426	1375
Federal Income Taxes	<u>1653</u>	<u>0</u>	<u>3443</u>	<u>2170</u>	<u>2532</u>	<u>3031</u>
Profits	<u>3215</u>	<u>3018</u>	<u>4854</u>	<u>5999</u>	<u>5483</u>	<u>4733</u>
Profit (\$ per barrel)	<u>5.45</u>	<u>5.23</u>	<u>8.54</u>	<u>11.27</u>	<u>10.43</u>	<u>9.14</u>

1977 - 1981

	<i>1981</i>	<i>1980</i>	<i>1979</i>	<i>1978</i>	<i>1977</i>
Revenue	16935	13095	8855	4243	717
Expenses:					
Depreciation	941	979	741	609	38
Operating Expenses	1020	617	514	538	46
Overhead	51	15	2	0	2
Interest	698	730	927	1049	117
Royalty	1596	1143	706	221	86
Severance Taxes	1291	924	622	195	76
Property Taxes	317	314	297	278	30
State Income Taxes	872	712	486	127	30
Windfall Profit Taxes	3089	797			
Federal Income Taxes	<u>2570</u>	<u>2703</u>	<u>512</u>	<u>17</u>	<u>32</u>
Profits	<u>4490</u>	<u>4161</u>	<u>4048</u>	<u>1209</u>	<u>260</u>
Profit (\$ per barrel)	<u>9.24</u>	<u>8.56</u>	<u>9.88</u>	<u>3.47</u>	<u>2.58</u>

18.

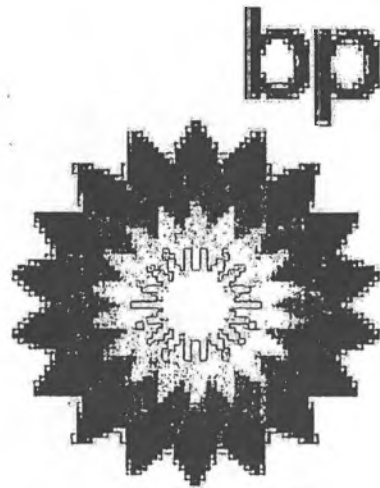
**BP Document re:
Cash Cow**

File name = DSP ELEC Sanction Mail.doc
Find numerous embedded documents

Exhibit No. SCA-588
Docket Nos. IS09-348-004 et al., RCA Docket Nos. PC09-9 et al.
Page of 7

Restricted

Alaska Business Unit
Mid-Stream Alaska
Trans-Alaska Pipeline Pump Station Electrification



Decision Support Package – Sanction
February 9, 2004

Table Of Contents

- 1. Executive Overview and Project Description**
 - 1.1 Recommendation
 - 1.2 Overview and History of TAPS
 - 1.3 Electrification Project Description: Old Vs. New Synergies

- 2. Business Case**
 - 2.1 Strategic Context and Business Objective
 - 2.2 Project Economics
 - Assumptions & Comparative Cases
 - Economics & sources of Value
 - PS 1 & 9 Power Options
 - Expected Value Base Case
 - 2.3 Principal Commercial Risks
 - Risk Descriptions & Mitigation Actions
 - 2.4 Economic Sensitivities
 - 2.5 Key Project Milestones

- 3. Execution Phase Planning**
 - 3.1 Project Execution Strategy & Plan
 - 3.2 HSE Management
 - 3.3 Contracting Strategy
 - 3.4 Execution Organization

- 4. Operate Phase Planning**
 - 4.1 Redefining the operating organization
 - 4.2 Regionalized Oil Spill
 - 4.3 Regionalized Maintenance

- 5. Assurance**
 - 5.1 Value Engineering
 - 5.2 No Wrecks
 - 5.3 Head of Discipline (HOD) Endorsement
 - 5.4 IPA

1. Executive Overview

1.1 THE RECOMMENDATION

The Alaska Business Unit recommends rebuilding 4 of the remaining TAPS pump stations by replacing aging mainline Avon Rolls Royce direct drive furbine pumps with high efficiency turbine electrical generators and electrical pumps; and replacing existing facility housing with "non-occupied structures" that require less maintenance. Electrifying the TAPS pump stations, coupled with lifecycle control replacement, will allow automation and reduce manpower at Pump Stations 1, 3, 4 and 9. Electrifying all of the pump stations translates to an annualized Operating & Maintenance cost savings of \$44mm (gross) by 2008 and will allow TAPS to forego more than \$114m in expense and \$44m Capital (gross) in costly upgrades to the aging Avons, associated facilities and their enclosure buildings over the next 10 years.

The BP Capital request is as follows:

\$ million	Gross Project	BP Net
Capital Requested for Sanction	\$172	\$81
Engineering Tolerance	20	9
Reference Value for Sanction	192	90

1.2. THE HISTORY OF THE TRANS ALASKA PIPELINE SYSTEM and TAPS Overview

The discovery of a giant crude oil field at Prudhoe Bay on the North Slope of Alaska in 1968 began a period of unprecedented petroleum industry activity in the state. Construction work associated with the Prudhoe Bay discoveries included installation of production facilities on the North Slope and an 800-mile pipeline from the oil fields to a marine tanker loading facility in the city of Valdez. This pipeline system, marine loading facility, and ship escort and vessel response system (SERVS) are collectively called the Trans-Alaska Pipeline System (TAPS).

Based on forecasted production and recovery lifecycles of the North Slope fields, the original anticipated economic life of TAPS was 25 years. However, due to enhanced recovery techniques, revised reserve volumes, and development of new fields, TAPS is now being positioned to operate for another 30 years.

To support this operational commitment, Alyeska Pipeline Service Company (Alyeska) and the TAPS Owners have initiated a redesign of the pipeline pump stations and control systems. The Valdez Marine Terminal and SERVS are also being studied, but these studies are not as advanced as the pipeline. Preliminary engineering for the pipeline pump station redesign was completed in 2003 and the TAPS Owners are evaluating the results.

TAPS was originally designed for a 1.5mmbopd throughput (excluding Drag Reducing Agents) and has been operated for 25 years using personnel to monitor pipeline and pump station operations. Although this practice has worked well, it is no longer cost effective. Current technology used by other pipelines all over the world includes electronic monitoring and control systems that are more efficient and reliable.

The pipeline reconfiguration project is a proposal to utilize those technologies to enhance TAPS operational efficiency. This "proven technology" will reduce future operating costs and maximize

efficiency far into the future. None of these changes compromise safety or operational integrity. In fact, safety, operational integrity, and environmental performance will be enhanced with Strategic Reconfiguration.

Background for Pump Station Strategic Reconfiguration (SR)

For several years, Alyeska has been engaged in engineering studies to identify ways to improve operational efficiency through technology upgrades, increased use of automation, and reduction of infrastructure to minimize transportation costs and extend the economic life of the pipeline and North Slope oil fields. This will be accomplished through equipment upgrades and the resulting reductions in Operations and Maintenance (O&M) costs.

The SR pipeline study was formalized in 2001 when an Alyeska Reconfiguration Studies team and TAPS Owners planning team jointly examined eleven proposed alternatives. The initiative was complete in January 2002 with a recommendation of two strategies for further study, electrification and hybrid (see following page). A third option, direct drive turbines, was later added to the list.

Electrification is the installation of electrically driven crude oil pumps at certain pump stations combined with increased automation and upgraded control systems. It includes a dramatic reduction of utility systems and associated facility infrastructure and allows un-staffing of pump stations.

The hybrid option strategy was an attempt to make best use of existing equipment while achieving the SR objectives of simplified infrastructure and reduced O&M costs. It consists of automation of existing crude pump drive packages and utility systems and includes the same upgraded control systems that would be installed for electrification. This option does not have capacity flexibility to accommodate future throughput changes and has been abandoned as an alternative.

The direct drive turbine option, a variation of the electrification theme using gas turbines instead of electric motors, incorporates many of the same concepts but is mechanically more complex and slightly less reliable. At the current stage of engineering, adopting this alternative implies expensive engineering and construction delays and therefore this alternative was abandoned.

Costs for each option were compared to an inertia case, which consists of the current practice of maintenance and equipment lifecycle replacement. This is the status quo case and subjects Alyeska to the lowest operating reliability and highest ongoing O&M expense of any alternative.

TAPS Construction History and Reliability

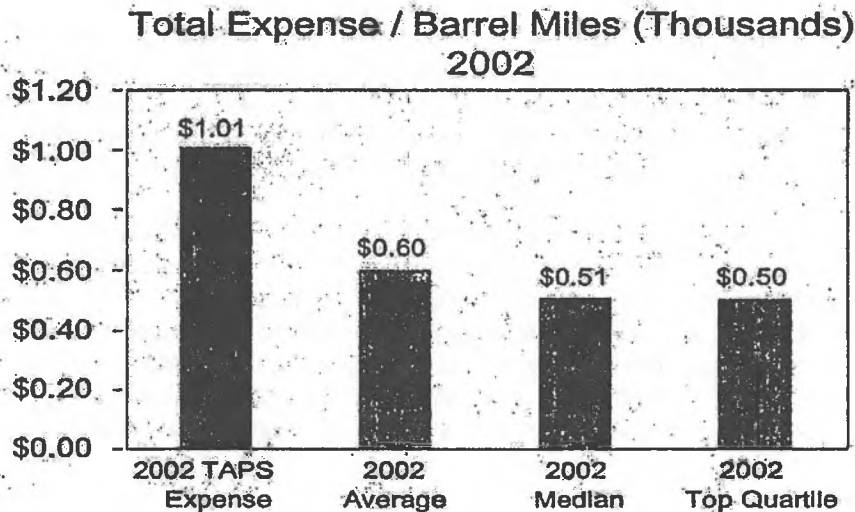
One of the first challenges in developing the North Slope fields was creating a transportation system to move the vast reserves of the Sadlerochit field in Prudhoe Bay to market. Engineers decided a large-diameter pipeline from the North Slope to a marine tanker loading facility at an ice-free port was the answer. Alyeska Pipeline was created to construct, operate and maintain TAPS for the Owner companies. Originally eight in number, TAPS Owners are now BP Pipelines (Alaska), Phillips Transportation Alaska, ExxonMobil Pipeline Co., Williams Alaska Pipeline Co. (whose interest is currently under a purchase agreement with Koch) and Unocal Pipeline Co.

Despite many engineering, political, and regulatory hurdles and a cost of more than \$8 billion, construction of TAPS was completed in June 1977. The first oil left Pump Station 1 on June 20, 1977 and the tanker *ARCO Juneau* steamed out of the Valdez marine terminal laden with Alaska North

Slope (ANS) crude on August 1 that same year. Since then, more than 14 billion barrels of ANS crude have been transported through the pipeline, with throughput peaking in 1988 at nearly 2.1 million barrels per day. Current throughput is relatively stable at just under 1 million barrels per day.

While reliability throughout the history of TAPS has averaged well above 99 percent, other pipelines have achieved this same reliability through the use of modern technology and automation. Due to steadily increasing regulatory oversight, aging of the system, increase in personnel costs and inherent inefficiencies in original design, TAPS has risen in cost per barrel mile to lead its U.S. large pipeline peers in the transportation cost category.

The chart below shows how TAPS compares to other large pipelines based on benchmark data obtained from the Association of Oil Pipelines (AOPL).



Preliminary engineering studies indicated the electrification option is the only alternative satisfying the project objectives of reliability, efficiency and cost-versus-savings. Direct drive turbines is the next best alternative, but has slightly reduced reliability and savings coupled with increased on-going maintenance. The hybrid case did not meet project objectives. Recommended implementation strategies for pipeline electrification are outlined as follows.

- Power generation upgrades, electrification and automation of Pump Stations 1, 3, 4 & 9.
- Consider removal, retirement and disposal of all above grade unused equipment and facilities at Pump Stations.
- Install control and communication modules at Pump Stations.

Electrification satisfies the following objectives established under Strategic Reconfiguration:

- Maintains safety and operational integrity.
- Improves operational efficiency and environmental performance.
- Shows highest economic rate of return with the least economic risk.
- Allows unstaffing of pump stations through remote control capabilities.
- Is scalable to future throughput requirements.
- Will maintain required reliability through use of technology rather than on-site staff.
- Is proven technology currently in use in the industry.

Pump Station Reconfiguration-Electrification Major Project Milestones

- Workforce plan approved – 4Q2003
- OSCP amendments approved – 4Q2003
- SCADA upgrade complete – 4Q2004
- Communications module installation complete – 4Q2005
- PS control systems upgrade complete -- 4Q2005
- PS1, 3, 4 & 9 electrification complete – 4Q2005

Methodology for Project Savings/Cost Determination

Alyeska used a rigorous methodology for the development of project scope and determining costs/savings. A strategic plan, developed by Alyeska's Planning Team, was adopted by Alyeska management and the TAPS Owners. This process resulted in two options for which conceptual design was completed: electrification/automation and inertia. Third party validation confirmed the cost and concept of each option and identified electrification/automation as the best choice. From this work, 2003 long range planning assumptions were defined and used as the basis for company-wide planning.

The Alyeska organization and the SR project team then embarked on parallel paths while working toward a common goal. The project team formalized project scope, completed preliminary engineering, developed an operations philosophy and finalized project costs. Simultaneously, company managers identified staffing requirements, major maintenance that could be eliminated, and determined project savings. Benchmarking with industry peers and verification by cross-functional groups within the company validated outcomes and identified additional savings opportunities and other synergies. Final assurance included executive review, approval and commitment.

1.3 Electrification: Old versus New

Although electrifying pump stations sounds complex, it is really a straightforward solution to achieve the project objectives of efficiency, cost reduction and extension of economic life of the system. This section compares facilities and process equipment installed on TAPS now to post-electrification and discusses changes to Alyeska's O&M philosophy.

Description of TAPS

TAPS is a crude oil transportation system that begins at PS1, the gathering and storage center for all North Slope producers, and terminates at a marine terminal storage and tanker loading facility located in Valdez on the shores of Prince William Sound. The 48-inch pipeline is 800 miles long, crosses three major mountain ranges, 34 major rivers and achieves a maximum elevation of 4,379 feet at Atigun Pass located 166 miles south of PS1. Of the 800 miles, 420 are above ground and 380 are buried, with 62 RGVs installed to reduce spill volumes in the event of a breach in the pipe.

Twelve pump stations are designed into the system although not all are active pumping stations. PS5 is a relief and reinjection station while PS11 is installed with mainline isolation valves only as its additional pumping capacity was never required. Of the remaining ten stations with pumping

Critical Energy Infrastructure Information

quantities of Drag Reducing Agent (DRA) were injected upstream. However, DRA is expensive and operating PS7 is more economical to meet horsepower and maximum operating pressure requirements at current flow rates.

As North Slope production began to drop off in the mid-1990's, full pipeline design capacity was no longer needed. As a result, five pump stations are currently off line in a stand-by configuration called rampdown. PS8 & 10 were ramped down in 1996, PS2 & 6 in 1997, and PS12 in 2003.

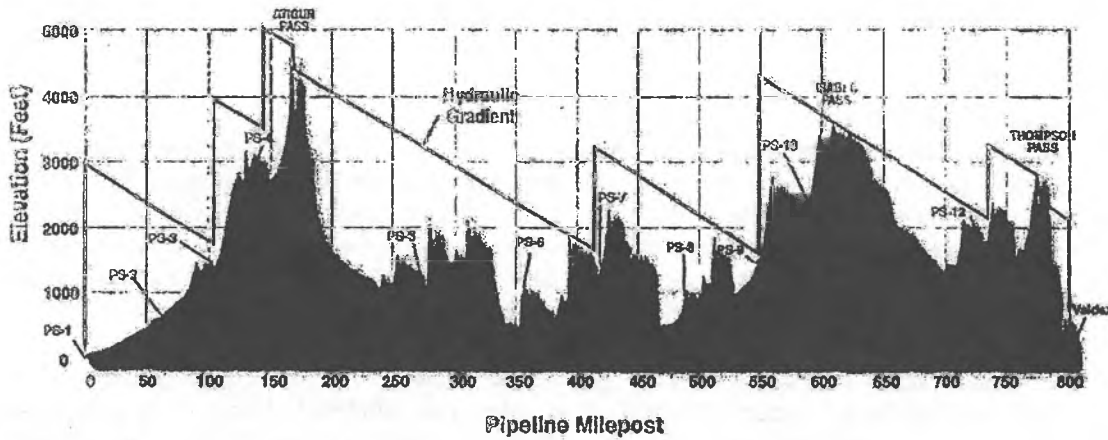
Pump Driver Package: Old Vs. New

The pump driver package installed on TAPS is a reliable but dated Avon gas turbine coupled to either a Byron-Jackson or United centrifugal pump. PS1, 3, and 4 drivers use natural gas as a fuel source while PS7 & 9 use liquid turbine fuel.

Each station with pumping capability has three such drive packages installed with the exception of PS2 & 7, which have two. During peak throughput in the late 1980's there were no spare drivers on TAPS; every installed unit was needed to meet horsepower requirements for the high flow rates. Although dependable over the years, these drive packages and appurtenances are complex and labor intensive to operate and maintain to the standards required on TAPS.

Electrification will replace the existing pump driver packages with skid-mounted electric motors and modern centrifugal pumps. The engineered design is very flexible and allows for many of these skids to be installed in parallel to accommodate throughput rates up to system capacity of over 2 million barrels per day (Mbd). Initially, three of these driver packages will be installed at PS1, 3, 4 & 9; this configuration supports throughput up to 1.12 Mbd. Adding two more skids at each location will provide 1.5 Mbd capacity. Taking units off-line will allow reduced throughput rates in the several hundred thousand barrel/day range while remaining within acceptable equipment operating parameters. Variable frequency drives (VFD) will be installed for control of the motors; replacement motor control centers (MCC) will handle power distribution.

Trans Alaska Pipeline System Elevation Profile

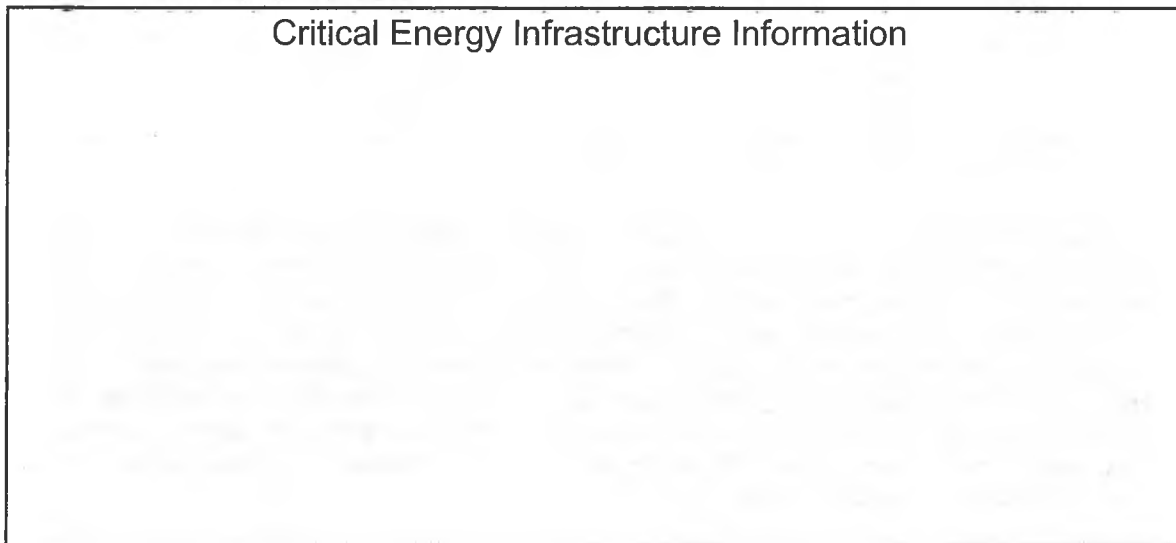


Power Generation: Old Vs. New

Due to the remoteness of TAPS, most pump stations need to generate their own electrical power. This is currently accomplished with various numbers of skid-mounted 450 kilowatt Garrett and 800 kilowatt Solar turbine generator packages. Due to obsolescence and age of equipment, it is increasingly difficult to maintain these generator sets. Under electrification, PS1 has the option to tie into the existing North Slope grid for power needs or self generate. Power generation at PS3 & 4 will be accomplished with modern skid-mounted turbine generators while PS9 will purchase power from a local utility. There will be no change at PS7.

PS1, 3 & 4 use processed natural gas received from North Slope producers for general fuel needs such as mainline pump drivers, power generation and facility heating. Following reconfiguration, this fuel gas will still be used for primary power generation.

Process Control: Old Vs. New



Critical Energy Infrastructure Information

Telecommunications: Old Vs. New

Critical Energy Infrastructure Information

Fire Systems: Old Vs. New

Fire detection and suppression is particularly important on TAPS due to remote facility locations. Fire systems currently installed at the pump stations include various combinations of smoke, gas and flame detectors that initiate suppression actions and equipment shutdowns; flooding agents include water, halon and foam. Many of these systems are designed around occupancy requirements of a staffed facility and will not be needed following reconfiguration.

Maintaining these systems has become particularly problematic in recent years because original pipeline design included large enclosed process areas (see photo). Fire codes have changed since TAPS was engineered. This has created compliance issues that can be more effectively resolved with new equipment.

Critical Energy Infrastructure Information

Housing, Utilities and Staffing: Old Vs. New

Even though some remote control capabilities are designed into TAPS, the pump stations are currently staffed 24 hours a day, 365 days a year due to equipment monitoring requirements, remote control system deficiencies, and oil spill response needs. This necessitates the pump stations to operate and maintain a wide range of life support utility systems such as potable water, wastewater, heating and ventilation, waste disposal, food preparation appliances, and vehicle refueling and maintenance. The extreme Arctic conditions under which these systems operate make maintenance difficult and expensive.

Additionally, field staffing requires a large infrastructure for such things as living quarters, office space, telephone and data systems, and a materials supply network. Remote airports are required, emergency evacuation must be considered, medical care provided and even such things as mail and package delivery accomplished. In essence, a typical pump station is equivalent to a small city with a resident population of 40 – 50 with peaks as high as 130 during busy project seasons.

With the application of new technology, that can be changed. The top photo below shows an aerial view of Pump Station 3 in its current configuration. Contrast that to the photo underneath, which is what PS3 could look like after SR and possible later removal of unused equipment when approved by Owners and regulators. It is easy to see the impact of Strategic Reconfiguration to installed infrastructure and facilities. There will be fewer buildings in use, simplified communications and process control, upgraded pump/driver packages, and no assigned staff. A reduction of approximately 15 percent of the total current workforce is possible because of the reduced workload.

New Technology – Less Infrastructure – Same Throughput

Critical Energy Infrastructure Information

Strategic Reconfiguration represents a 30-year leap in technology. This new technology requires far less infrastructure, and operating facilities are greatly simplified.

At top left is an aerial view of PS3 in its current configuration. Note the large number of buildings, interconnecting hallways, and outlying support facilities. Because pump stations are currently staffed around the clock, on-site housing is required, creating the need for life support systems such as water and wastewater treatment, heating, food preparation, trash incineration, fire suppression, vehicle maintenance and additional power generation.

By implementing modern technology, the need for full-time staff is eliminated. This means the decommissioning or removal of housing units, reduction of utility systems, and elimination of support facilities.

The lower photo depicts PS3 post-reconfiguration; as can be seen, the changes are significant. TAPS-wide, at

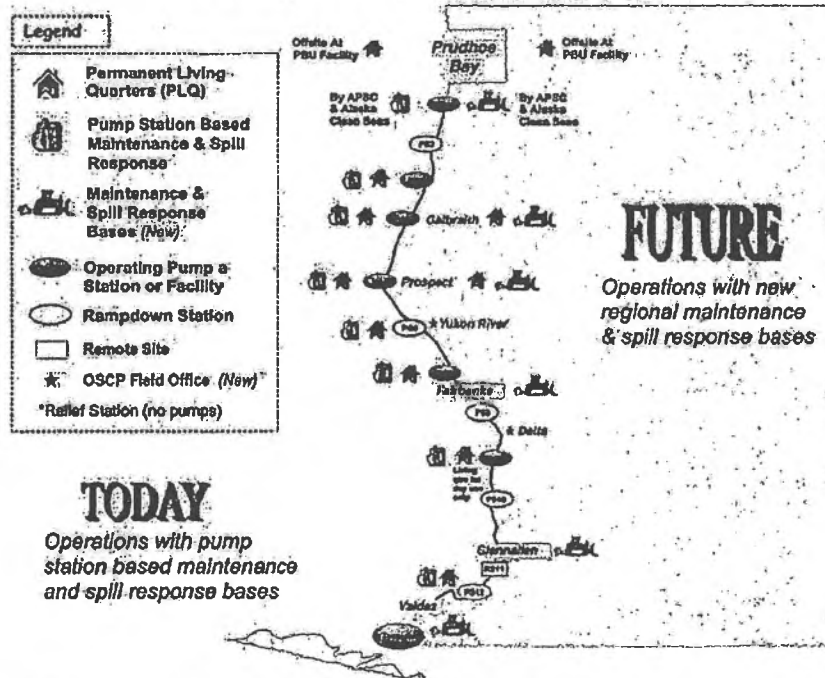
least 75 buildings could be decommissioned and 27 more could be simplified. Removing work from the system provides significant, sustainable cost reductions.

Synergies: OSCP/Support Services/Maintenance

Although pipeline SR as a stand-alone concept is strictly a technology driven solution to achieve efficiency and cost savings, there are several other business considerations that, when combined with SR implementation, will produce increased operating and business efficiencies. These synergies are outlined below.

- Oil Spill Contingency Plan (OSCP) amendments accommodate unstaffing of remote facilities while maintaining and/or improving response capabilities using regional response bases and additional pre-deployed equipment. Although the total number of staff in the field will be reduced, the number of initial responders will not change.
- Operations philosophy changes as a result of electrification allow elimination of all operation technician functions as well as a greatly reduced infrastructure of buildings, services, and field-based support groups.
- Maintenance philosophy changes allow centralized dispatch for scheduled maintenance. This approach creates efficient use of personnel while supporting OSCP amendments and ongoing Right-of-Way (ROW) maintenance.

TAPS Maintenance and Spill Response



- The scalability of the electrification solution accommodates a wide range of future increases or decreases in throughput and allows those changes to be accomplished at a much lower cost.

Critical Energy Infrastructure Information

Details of the design can be found in the Preliminary Engineering Design Report:



Prelim Eng Main
Doc.pdf

2. Business Case

2.1 Strategic context and Business Objectives for the Alaska Business Unit

As described in the Pump Station Electrification Appraise FM of March 2003, Alaska's role in BP's portfolio is to provide a stable production base and cash flow to fuel growth elsewhere in the business while improving margins and returns. Driving cost savings in TAPS is a key element in delivering margin improvement of BP's North Slope production.

Over the past three years the TAPS Owners and Alyeska have studied a number of potential business efficiency opportunities. Preliminary engineering studies confirmed that Pump Station Electrification is the single largest driver of pipeline cost improvement and efficiency. Preliminary engineering studies have also confirmed electrifying and automating all 4 pump stations will allow Alyeska to eliminate over 285 full time positions, many of those in field locations where wage and locations premiums are very high. Currently, remote crews at these pump stations require expensive catering, transportation and other costly support services systems. Eliminating these positions translates to an annualized expense savings improvement of over \$41mm gross (+\$16mm net BP) by 2007 over APSC 2003 Base O&M.

2.2 Project Economics

Assumptions:

Electrification was modelled against a "Base/Inertia Case". The Base Inertia Case assumes continued use of the Avon-driven pumps, normal upgrades to remaining facilities and a reasonable allowance for continued operational improvement. In 2012 O&M is increased by \$4m annually to account for expected higher annual maintenance caused by turndown effects.

The Electrification case assumes self generation at PS 1, 3 & 4. It assumes GVEA power is supplied via the existing power grid to PS 9.

The Electrification case assumes that beginning about 2009 the APSC annual License to Operate Capital will decrease about \$6m under the Base/Inertia Case due to reduced Corporate Projects. This reduction is consistent with the capital funding expected in the APSC Long Range Plan and matches the BP estimate for Non-Pump Station related capital projects after electrification.

The Electrification Case assumes P ^{Highly Confidential Material Redacted} Savings and P ^{Highly Confidential Material Redacted} Capital. It also assumes ^{Highly Confidential Material Redacted} of the annual O&M savings accrue starting in 2006, with full savings in 2007. It assumes some buildings at the reconfigured pump stations can be abandoned in place.

^{Highly Confidential Material Redacted} Inflation was applied to O&M and Capital costs. Throughput was assumed to be declining at a ^{Highly Confidential Material Redacted} annual rate (and used to calculate fuel savings).

BP's equity in TAPS is 46.9% and our throughput share is assumed to average ^{Highly Confidential Material Redacted} over the period of evaluation. This is a cost reduction investment hence there is no sensitivity to oil price.

Sources of Value:

BP value is manifested in improved wellhead netback prices due to reduced tariffs. Summary economics are presented in the table below.

Summary Economics (Electrification vs. Base Case)		Highly Confidential Material Redacted	
	Sanction Capital (Net) \$m	Past Savings Thru '03 Gross (Net) \$m	Highly Confidential Material Redacted
Midstream	81	32 (12.7)	
Upstream	-	-	
AK11U	81	32 (12.7)	

Financial Impact (Electrification vs. Base Case) \$m										
Alaska BU	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Tariff Change (\$/bb)	\$0.00	\$0.05	\$0.06	(\$0.09)	(\$0.10)	\$0.00	(\$0.05)	(\$0.12)	(\$0.21)	(\$0.36)
Opex Savings	1.8	4.3	11.9	24.3	23.8	24.1	21.5	22.3	20.5	27.6
Incremental Capex *	(47.4)	(48.3)	2.6	2.6	1.2	3.7	2.8	2.6	2.8	4.6
Post Tax Cash Flow	(37.4)	(44.3)	13.9	25.4	15.7	16.9	17.8	18.8	16.9	23.5
RCMP Impact	1.1	1.2	6.9	17.5	16.8	19.0	16.4	17.2	15.2	21.4
Net Income Impact	0.6	0.6	4.3	11.2	10.7	12.2	10.5	11.0	9.7	13.7
NI/boe	\$0.01	\$0.01	\$0.05	\$0.14	\$0.12	\$0.13	\$0.12	\$0.15	\$0.15	\$0.23

* Incremental Capex includes life cycle replacement expenditures.

PS 1 and PS 9 Power Options

Optimizing the investment and commercial terms for power purchases at PS 1 and PS 9 are key drivers of value. At PS 9 Golden Valley Electric Association (GVEA) will provide commercial power through a utility grid. Delivery of power to PS 9 will require GVEA to upgrade their transmission system. GVEA will pass on that cost to APSC either through an installation fee or through a rate premium. Negotiating the cost of this upgrade into the power rate saves \$10.6m gross in CAPEX. At PS 1, sharing power with the Prudhoe Bay Central Power Facility could save \$16m gross in CAPEX. The recommended target case assumes PBU will provide no power since the PBU Owners have failed to deliver a Memorandum of Understanding for Power Costs.

Expected Value "Base Case" for Subsequent Value Tracking

Details of the expected Value Case are presented below. Electrification investment spending occurs primarily in 2004 and 2005.

Table 2. Investment Profile

APSC Investment Profile (APSC Gross CAPEX)	2004	2005	2006	2007	2008	2009
Inertia Base Case Capex	53.8	61.3	60.4	59.2	59.3	60.0
Elect Investment Case Capex (21mW, no LB CAPEX)	147.0	176.1	58.0	54.0	58.0	57.0
Net Incremental Investment	93.2	114.8	-2.4	-5.2	-1.3	-3.0

Savings delivery is best tracked on a gross APSC basis. The case below assumes that the incremental O&M Savings is deliverable through electrification. Note that the underlying performance improvement is about \$41m.

Table 3. Savings

APSC Gross Spending/Savings Profile	2004	2005	2006	2007	2008
Inertia Case	451.9	480.3	471.6	420.4	403.2
Electrification Case (17 mW, no LB CAPEX)	447.2	456.2	426.3	355.3	343.3
Avoided Major Maintenance	4.6	23.9	21.5	18.4	18.7
Incremental Annualized O&M Savings	-0.1	-0.1	-23.9	-46.6	-41.3

2.3 Principal Commercial Risks

Regulatory: Any major change in TAPS facilities requires Joint Pipeline Organization (JPO) and Alaska Department of Environmental Compliance (ADEC) approval.

The JPO has been supportive of the project and has confirmed through its own benchmarking exercise that TAPS electrification will better align the operation with other North American pipeline systems in terms of facilities and operations. The Argonne Benchmarking Study is attached:



JK001.pdf

Conditional approval was received from both agencies as of December 31, 2003.

JPO Finding of No Significant Environmental Impact:



Fonsl.pdf

JPO Notice to Proceed with Stipulations:



03-009RN.pdf

ADEC approved the OSCP on December 31 with "Specified Conditions". The "conditions" have no impact on project economics or schedule.

ADEC OSCP Approval:



JK001.pdf

RCA Issues:

We have considered the risk that the Regulatory Commission of Alaska (RCA) will exert approval authority over the proposed facility changes. The Owners have worked to mitigate this risk by clarifying to the RCA the separate nature of Electrification and the decision to remove ramped down facilities. Additionally, BP has prepared a legislative solution in case the RCA seeks to intervene. Should the RCA move to disallow Electrification cost recovery on intrastate shipments, such costs would be rolled over to our interstate tariff for recovery hence there should be minimal impact to value.

Dismantlement, Removal and Restoration:

Costs associated with dismantlement, removal and restoration (DR&R) of the affected stations (1, 3, 4 & 9), estimated at \$10m (\$4.7 m BP net), are excluded from the economics. These costs are

deemed discretionary, as the associated structures can be abandoned in-place until such time as the TAPS Owners move forward with a sanctioned DR&R project. There remains a minimal regulatory risk that the TAPS Owners could be challenged to remove idle equipment from TAPS.

Sanction/Schedule/Governance: Achieving sustainable savings from manpower reductions requires executive will. Given our governance role through the Owners Committee, BP is well positioned to ensure the proper focus and incentives are in place to assure delivery. As indicated in the graph below, a delay in delivering costs savings by one year could result in significant BP NPV loss. The Alyeska President is firmly committed to achieving and sustaining projected cost reductions with many of the organizational realignment activities already underway in anticipation of sanction.

Management of Change: Assuring successful cutover to new operating facilities is an important factor for staff and regulatory support. We do not have a robust transition plan in place today. However, Alyeska has appointed a senior leader with single point accountability to create a comprehensive MOC plan. Additionally, BP will elevate MOC focus to the Owners Committee to ensure executive ownership.

Project Cost Management: Cost and scope control are critical considerations for delivery. Extra measures are in place to ensure that the project is ring-fenced from other project spending to avoid scope-creep or inappropriate time-writing to the project. APSC has appointed a commercial leader to manage project logistics, SCM and provide robust cost controls. BP will require transparency in monthly project financial reports to the TAPS Owners.

Higher Grid Power Costs – The cheapest source for electrical power at PS 1 is spare capacity from the Prudhoe Bay Unit Central Power Station, however only about 4 MW are available. The PBU Working Interest Owners have failed to deliver requested commercial terms to APSC. As a result, the project assumes all PS 1 power will need to be self-generated.

Savings Delivery – About 50% of the anticipated savings is derived from the reduction in the support organization due to fewer field-operating personnel and less anticipated engineering support. Achieving these savings requires a major manpower severance program and careful management of change to ensure that operating integrity is not sacrificed. It is also important to ensure that all expected savings are captured. Roles and accountabilities in the re-organization have been defined. A severance plan has been created.

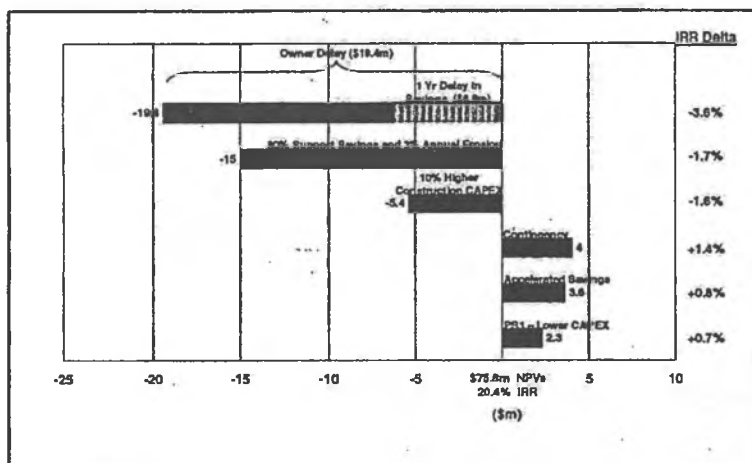
Other Risks-Alyeska has created the following detailed risk mitigation plans to assure operating integrity and safety including:

- Safety Management Plan
- Environmental Management Plan
- Workforce Reduction Plan
- Critical Skill Retention Study and Plan
- Project Execution Plan
- Quality Management Plan

Technical Risk Issues and Track Record – The technology to automate and electrify pump stations is not new, virtually all of Alyeska's peers in the recent AOPL Pipeline benchmarking study have automated pump stations. The primary driver of cost difference between TAPS and AOPL comparator Pipelines is driven by this lack of automation.

2.4 Economic Sensitivities

Below is a summary of value adding options/Economic Sensitivities and their impact on project economics:



Sensitivities & Value Adding Options / Delivery Risks

- **Owner Delay** – Delay would result in loss of value due to opportunity loss, addition of mandatory life cycle spend that had been previously deferred, loss of accelerated federal tax depreciation benefits, and additional project team cost.
- **Under-delivery of Savings and Erosion** – Executive will be required to deliver and sustain projected cost savings. Management commitments and governance processes are in place to assure delivery.
- **Capital Cost Overrun** – Adequate FEL has been performed and project management systems are in place.
- **Contingency/ Value Engineering** – Delivery of project contingency capex savings through ongoing value engineering processes.
- **Accelerated Savings** – Early delivery of organization opex savings pre-startup.
- **PS1 Lower Capex (PBU Power Purchase)** – Option to purchase part of Pump Station 1 power requirement from PBU.

2.5 Key Project Milestones and Schedule Overview

Milestones

BP SET Approval	February 2004
TAPS Owner Approval	March 2004
Award of Major Contracts	April 2004
Facility foundation work	Summer 2004
Remote Communication Module tie-in	Summer 2004
Module Shipment and connection	Spring 2005
Start-up and Testing	October 2005
Commissioning	December 31, 2006

Project Schedule Overview

The project is operating on a tight schedule in order to meet fire system commitments and to obtain tax benefits by December 31, 2004. Realizing organizational savings as quickly as possible is leveraging.

Delay of the project will result in lost O&M savings, lost tax benefits, increased major maintenance costs (including fire and gas system upgrades), and increased program management costs. The unfavorable impacts of a one-year delay are estimated in the range of \$40 million to \$60 million.

Key deliverables are as follows. See the attached project schedule for additional details.

AFE Approval	March 1, 2004
Authorize equipment manufacture	March 1, 2004

Tie-ins (2), RD Comm. Modules
PS 4, PS 5, PS 7 & PS 9 foundations
Major equipment in fabrication shops
Module piling at PS 1 & PS 3
Module shipment, start interconnect
Mechanical Completion
Startup and Commissioning

Summer 2004
Summer 2004
Fall 2004
Winter 2005
Spring 2005
October to December 2005
November 2005 to Jan 2006

3.0 Execute Phase Planning

3.1 Project Execution Strategy and Plan

The project execution plan outlines the purpose of the project, the organization of the project management, and is composed of sub-plans in safety, Construction, Procurement, Environment and Quality Management.

It defines the project scope, describes the physical changes in the facilities, describes the "Project Success Factors" and sets project cost targets.

The execution plan also defines the roles and accountabilities for project personnel. Details of the Project Execution Plan can be found in the attached document:



Project_Execution_Plan.pdf

3.2 HSE Management and Issues

HSE Planning and Strategy

A complete Environmental Management Plan was developed for Pump Station Electrification that describes the permitting and compliance management processes required for executing the Pipeline Electrification Project. It is included below:



PEP HSE p8-10 .pdf

An Environmental Assessment (EA) was also completed and is provided in the Reference Documents. The EA concluded that Pump Station Electrification project will significantly reduce the environmental impact of the TAPS System.



Env Mgt Plan Rev 0
DRAFT Nov 7...

A complete Safety Management Plan has been created for the project including a preliminary HAZOP, Safety Integrity Level analysis and Risk Assessment. The details of the HAZOP are included in the following document:

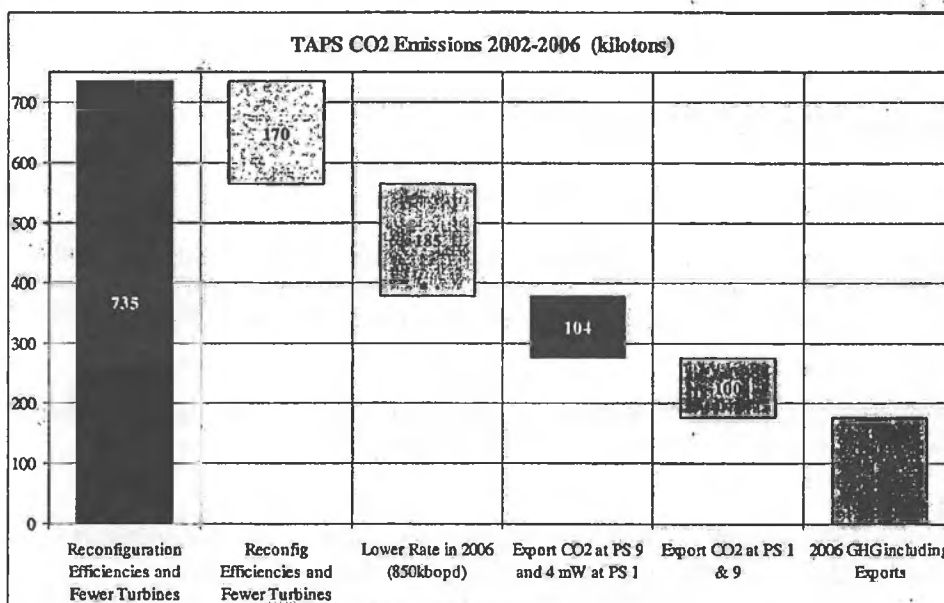


Hazop.pdf

Emissions Reductions

This project will significantly reduce the physical footprint of TAPS pump stations, eliminate about 50% of the current TAPS CO₂ emissions and improve safety by reducing manpower in the field where historically the highest “recordable incident” rates have occurred.

A significant reduction in air emissions will occur when the Rolls Royce Avon turbines are eliminated:



These modeled Carbon Dioxide reductions were estimated using an APSC fuel consumption model.

3.3 Contracting Strategy

During Preliminary Engineering a contracting and procurement strategy was developed for the execution phase of this project. The details of that plan can be found in the following document:



PEP Contracting Strategy p28-35.pdf



Contracting Plan -
SRP 10.02.0...

3.4 Execution Organization

The project organization developed to execute the final design and construction of the Reconfigured Pump Stations was developed in the Preliminary Engineering phase. Organization charts representing those organizations can be found in the following document:



PEP Exe Org Exhibit 1-2-3 p65-67.pdf

4.0 "Operate Phase" Planning

4.1 Redefining the operating organization:

The shift to automated pump stations requires addressing 3 groups of operating personnel, the pump station operators, pump station maintenance personnel and pump station oil spill support. The pump station operators will be replaced by telemetry and station controls. They are eliminated from the future organization.

Oil Spill response will be regionalized as described below. No significant reduction in OSCP staff will occur however they will be redeployed along the line.

4.2 Oil Spill Plans

Since construction, TAPS utilized Oil Spill Responders and equipment staged at operational Pump Stations along TAPS. De-manning the pump stations requires redefining the oil spill contingency plan to be able to provide the same level of oil spill response by responders now based in Regional Oil Spill Centers rather than at the pump stations. ADEC and the JPO have

Critical Energy Infrastructure Information

The details of the Regionalized Oil Spill Plan can be found in the attached document:

(Insert Oil Spill Plan)

The new plan has no reduction in spill responder staff, and no net reduction in response time for the secondary responders. The relocation of staff to urban centers and a transition of some of the staff to urban work schedules will reduce costs.

Both the JPO and ADEC have conditionally approved the Regional Oil Spill Plan despite public criticism from an APSC Maintenance Supervisor. That criticism was directed at training, supervisor/worker ratios, initial response capabilities and equipment staging locations. Both

APSC and the JPO seriously considered the issues raised and many were either addressed by APSC internally or addressed by the JPO in their conditional approval letter.

4.3 Regionalized Maintenance

Pump Station maintenance personnel will also be re-deployed through a "regionalization". Maintenance Centers will be located at Prudhoe Bay, Galbraith, Prospect, Fairbanks, Delta, Glenallen and maintenance staff will be withdrawn from the Pump Stations.

5.0 Assurance:

Throughout 2003 APSC, and their contractors (SNC-Lavalin and Hinz), undertook a series of peer reviews with the TAPS Owners and other appropriate oversight groups. These included three BP "No Wreck Reviews" (June, October and January 2004), two IPA FEL reviews (November and January 2004), a "Value Engineering" challenge session (December 2003) and five cost review/challenge sessions. Those assurance activities are described below and documented in Section 8 (Reference Documents).

5.1 Value Engineering

Value Engineering Overview

A Value Engineering Study was completed for Alyeska Pipeline Services Company (APSC) on the Strategic Reconfiguration Project, Pump Station Electrification and Control System Automation scope, for the Trans Alaska Pipeline System (TAPS).

The initial Value Engineering Study was completed on November 5th, 6th and 7th, 2003. The Preliminary Engineering Design phase of the project has been completed and the project team is working on a transition engineering phase pending project approval by the TAPS Owners.

The objectives of the VE Study were to:

- A. Identify cost saving opportunities and improvements to the value of the design.
- B. Select the minimum scope necessary to reduce operating costs by de-manning pump station facilities.
- C. Do so without compromising reliability, availability, safety and system integrity goals established for this project.

Value Engineering Key Results

The VE team prepared 56 idea proposals and based on the proposal evaluations made recommendations to APSC Project Management. Of the 56 idea proposals produced, 8 idea proposals were deferred for further evaluation during detailed engineering, 27 were rejected and 21 were accepted.

The successful implementation of these 21 idea proposals could result in a total savings of \$18,033,000.

The detailed Value Engineering Report:



VE Final Report.doc

5.2 No Wrecks

At the request of BP, APSC held a series of "No Wreck" reviews in the BP format with "No Wreck" tools as guides to facilitate peer discussion of the Electrification Project.

Three "No Wreck Reviews" were held, one in June 2003 to get an early view on project status and to ensure that key risks were identified and addressed in the Preliminary Engineering Studies. This meeting identified gaps associated with operations integration and important risks associated with regulatory issues (Regulatory Commission of Alaska).

The second "No Wreck" was held in October 2003 and meant to determine how close the project was to sanction and to identify gaps to close before 1Q 2004 sanction reviews began. This review helped to more clearly define the TAPS Owner expectations around risked costs, Value Engineering, and the separation of the project from other ongoing reconfiguration activities.

A final "No Wreck" was held in January 2004 as a final test to determine if the project had adequately addressed the October No Wreck feedback and to prepare a forum in which technical experts could review the preliminary engineering studies and if appropriate endorse the project.

A summary of the final Jan 2004 "No Wreck" feedback:



TAPS One pager
.doc

5.3 Head of Discipline (HOD) Review and TVP Endorsement

Concurrent with the final "No Wreck Review" technical endorsements were received from EPTG Operations, Energy Efficiency, HSE, EPTG rotating equipment specialists, EPTG electric motor specialists and EPTG Projects. Those endorsements are included in the document above. Detailed feedback from the HOD Reviewers is included in the Powerpoint presentation below:



TAPS Review Peer
Feedback.ppt ...

5.4 IPA

Two IPA reviews were held. The first was in November 2003 when very little formal documentation for the project existed and again in January, 2004, after virtually all of the Preliminary Engineering documentation was complete.

The January IPA review revealed an FEL Index of 5.0 . That FEL index level is consistent with well planned major projects and benchmarks very favorable versus other successful BP Major Projects.



IPA Final Report
2.16.04.pdf

19.

Therriault Email

From: Jim Dodson [mailto:jdodson@investfairbanks.com]

Sent: Monday, August 02, 2010 10:02 AM

To: Jim Dodson; Ali Knabe (ali.knabe@alaska.edu); Andrew Niemiec (andrew_niemiec@dot.state.ak.us); Andrew P. Garrigus P.E. (agarrigus@myeterra.com); Andy Warwick (warwick@gci.net); B.B. Allen (Bill_Allen@commerce.state.ak.us); Bill Satterberg (bill@satterberg.net); Bob Hajdukovich (info@frontierflying.com); Bob Hajdukovich (bob@frontierflying.com); Brian Rogers (chancellor@uaf.edu); hbfate@gci.net; buz@jackovich.com; croberts@ci.fairbanks.ak.us; d_westlake@hotmail.com; Jim Dodson; Gary Wilken (garywilken@me.com); Gene Therriault (genet@gci.net); Jeffrey J Cook (jeff.cook@fhr.com); John Binkley (jbinkley@alaska.net); Michael K. Henry; Mike Kelly (representative_mike_kelly@legis.state.ak.us); rwienn@florcraft.nu; Tim Beck (tbeck@ptialaska.net); Tim Beck (tbeck@ptialaska.net); Bill Sackinger; Chris Storhok (cstorhok@co.fairbanks.ak.us); Dave Hoffman; DeLaina Storhok; Doug Smith; Frank Abegg; Jim Whitaker (jwhitaker@acsalaska.net); Luke Hopkins (mayor@co.fairbanks.ak.us); Therriault, Gene (GOV); Paul M Park; Paul Martz; Paul Metz (ffpam@uaf.edu); William Sackinger; Amy Cook (acook@carlile.biz); Bob Shefchik; Carol E. Lewis (celewis@alaska.edu); Cynthia Henry (hops@gci.net); Damian Thomas (damian_ak@hotmail.com); Dan Britton (dwbritton@fngas.com); Dan Gavora (dgavora@doyonutilities.com); Jack Hebert (jack@cchrc.org); Jesse VanderZanden (jesse.vanderzanden@alaska.gov); Kathryn Dodge (kdodge@co.fairbanks.ak.us); Luke Hopkins; Matt Want; Steve Lundgren (slundgren@denalystatebank.com); Terry Strle; Tony Johansen; (scott.v.bell@gmail.com); Buzz Otis; Buzz Otis; James M. Collins; Jerry Sadler (AERINC4@alaska.net); Jim Haseiberger (jimh@alaskatent.com); Jim Johnsen (johnsenj@doyon.com); Joe Faulhaber (hellojoe02@gmail.com); Paul McCarthy; Paul Robinson; Ralph Seekins; Reinhard Neuhauser; Tim Cerny (tcerny@fdifairbanks.com)

Subject: Gene Therriault response to my distribution of the Alaska Digest article

Please find below Gene Therriault response to my distribution of the Alaska Digest article. Following Gene's response is my reply to Gene (in blue)

Jim

Dear Jim:

On July 12 you e-mailed a copy of a column written by Brad Keithley with the following comment from yourself:

"I have attached, for your information, an article I copied from the Alaska Dispatch. After reading this article I hope you question, as I do, the focus that some of Alaska's political leaders have on building a gas line for the purpose of

exporting Alaska gas. State gas revenue is not going to replace the revenue the state receives from oil production. Business as usual is not working”.

I believe Mr. Keithley's column suffers from a fundamental lack of understanding of the geology, engineering and economics of energy production on the North Slope of Alaska. In order to provide a more complete picture of what the administration is doing to encourage oil and gas development in Alaska, I offer the following information.

Despite the suggestion to the contrary, Governor Parnell is focused on future oil and gas development in Alaska. However unlike oil, North Slope natural gas requires a new pipeline to be constructed in order for the reserves to be commercialized. This infrastructure is critical for development of our gas reserves and for long term production of oil on the North Slope.

Like many world class basins, the North Slope has a large endowment of both oil and natural gas. In basins of this magnitude, production of oil is typically initiated first because it generates a higher rate of return on investment than gas. Over time natural gas becomes a more important economic component of the field as the easiest and least costly oil is produced. Finally, when the gas is monetized, it benefits from the infrastructure investments that have already been amortized and helps to carry a portion of the ongoing operation and maintenance costs of the fields. This sharing of infrastructure lowers the exploration and development risk for additional oil and gas to be produced from the field. This increases the economic value of marginal oil fields and extends the life of existing but declining oil fields. Two examples of this trend are the Gulf of Mexico Shelf and the Western Canadian Sedimentary Basin

The suggestion that Governor Parnell is backing efforts to access our natural gas resources on the North Slope just to fill the state treasury and in doing so has miscalculated the revenue that gas will produce is false. A natural gas pipeline benefits all Alaskans as well as the North Slope producers. In addition to state revenue, the pipeline will provide residents with access to a long term supply of reasonably priced energy as well as employment opportunities. The revenue stream from a large diameter pipeline was modeled three years ago and determined to be significant. Under expected prices scenarios, a North Slope gasline delivering 4.5 BCF of natural gas and natural gas liquids per day is projected to produce an average total annual revenue after tariffs of more than \$10 billion for the state, producers, and the federal government to split. The states revenue share alone will be in the billions of dollars per year.

The volumetric component of this operation is critical to keep in mind not only for the potential revenue stream but perhaps more importantly because shipping costs per unit

drop significantly as the volume transported goes up. In addition, as gas production increases, it will carry a larger portion of the existing operating costs relieving the economic pressure on remaining oil that exists in harder to produce formations and smaller less economic fields. In order to maximize the economics of a gasline project to the upstream owners (highest wellhead value), the transportation tariffs and processing costs need to be minimized. This is done in large part by maximizing the volume and BTU value of the gas transported which creates very beneficial economies of scale and much lower tariffs.

The beneficiaries of increased gas production and lower transportation costs will not only be the producers and the state treasury. Individual Alaskans will also benefit as the cost of the providing natural gas energy in-state goes down delivering more affordable fuel and a lower cost feed stock for value added processing. Decreasing the cost of transportation and processing through creation of a high volume operation will also lower the barrier to entry for natural gas production from new discoveries and previously discovered but undeveloped fields. If companies know they will be able to get either resource to market, they are more likely to drill wells.

Today, companies put off drilling certain exploration wells if they believe they are more likely to find natural gas than oil. Extending the life of older oil fields and improving the economics for new developments and discoveries including viscous oil means that more oil will flow through TAPS, slowing or reversing oil decline and extending the life of the pipeline. All of this activity will result in trucking jobs, maintenance jobs, exploration jobs and countless other jobs associated with expansion of activity on the North Slope. These are the economics Governor Parnell is striving to achieve by linking our world class natural gas resources to the market. In short, development of natural gas means development of more oil.

It appears that one of the main objectives of Mr. Keithley's piece is to strike at the validity of the ACES oil and gas tax. He mounts this challenge by suggesting that as a result of passing the ACES tax in 2007 ConocoPhillips has now experienced its first summer season in 40 years with no active onshore exploration. What Keithley fails to disclose is that ConocoPhillips did have onshore activity planned for the 2010 summer season; however, this activity was curtailed when the US Army Corps of Engineers failed to issue the necessary permits for a new river crossing of the Colville River. This permit difficulty has been widely reported in the press including the August 1, 2010 Petroleum News which carried the following statement:

ConocoPhillips next planned step-out from Alpine, the CD5 or Alpine West development, lies in the extreme east of the National Petroleum Reserve-Alaska. This development has been stymied by a refusal by the U.S. Army Corps of

Engineers to allow the construction of a bridge across the Nigliq Channel of the Colville River.

Mr. Keithley also fails to acknowledge that as a net profit tax mechanism coupled with investment credits, ACES taxes less profitable fields at a lower rate and provides incentives for encouraging their development. The article also does not mention the increased tax credits and deductions that Governor Parnell won in legislation he proposed this year (nor the ones he proposed that the Legislature did not approve) that have increased the incentives to invest in new development in Alaska.

Major producers like ConocoPhillips and BP have reported strong profits from their Alaskan operations under the ACES system. For example, in 2009, ConocoPhillip's Alaska activity accounted for 12% of its worldwide production but 29% of its corporate profits. In addition, the August 1, 2010 edition of the Petroleum News recently detailed ConocoPhillip's current year earnings and concluded that "ConocoPhillips' exploration and production activities continue to be more profitable in Alaska than across the Lower 48".

Keithley also makes the assertion that smaller, more nimble oil and gas exploration and production companies do not have the resources, financial, technical or managerial strength to develop projects in Alaska. However, he does not address the success of companies like Pioneer Resources, Armstrong or Anadarko Petroleum in our state.

Finally, the Chukchi and Beaufort Sea portions of the OCS have both proven large oil and gas discoveries and significant potential for world class discoveries. Governor Parnell has been and remains a strong and vocal advocate in Washington DC for increased access to these areas for exploration and development. It was the unfortunate spill in the Gulf that has lead to a deferral of this activity by the Secretary of Interior. This deferral has delayed multibillion dollars of planned investments offshore of the North Slope by Shell and others.

I hope this message provides useful information as you engage in discussions on Alaska's oil and gas future. Having previously worked as a Deputy Director for the Alaska Division of Oil and Gas as well as past employment with ConocoPhillips Alaska, I believe Governor Parnell understands the balance that must be struck to encourage full development of North Slope's potential while protecting the shareholder rights of the Alaska citizens.

Please consider forwarding this message to the distribution list that you sent the Brad Keithley column to. If you would like a clean copy as a word document, please let me know and I will send it to you.

Gene Therriault
Senior Policy Advisor on In-state Energy

Dear Gene and Gary,

The reason I sent out the AD article was to demonstrate that Alaska's natural gas is not going to replace the value, to state government, of Alaska's crude oil production. The simple truth is that natural gas has a dollar value of on a btu equivalent basis of 1/8 or less of that of crude. In other words Gary's old "Bridging the Gap" model does not work. The discussion we are having and the political leaders (McGuire, Ramras and company) I am talking are those that are proposing to build a in-state bullet line from the North Slope to Cook Inlet for the purpose of reducing Anchorage's energy shortage and exporting the balance. That is business as usual and in case you haven't notice, business as usual is not working. I would be more than happy to discuss this in more detail and if I had your distribution list I would include them on my reply.

Jim

Jim Dodson
President & CEO



907-452-2185

jdodson@investfairbanks.com

www.investfairbanks.com

From: Jim Dodson

Sent: Monday, July 12, 2010 9:15 AM

To: Ali Knabe (ali.knabe@alaska.edu); Andrew Niemiec (andrew_niemiec@dot.state.ak.us); Andrew P. Garrigus P.E. (agarrigus@myeterra.com); Andy Warwick (warwick@gci.net); B.B. Allen (Bill_Allen@commerce.state.ak.us); Bill Satterberg (bill@satterberg.net); Bob Hajdukovich (info@frontierflying.com); Bob Hajdukovich (bob@frontierflying.com); Brian Rogers (chancellor@uaf.edu); hbfate@gci.net; buz@jackovich.com; (croberts@acsalaska.net); d_westlake@hotmail.com; Jim Dodson; Gary Wilken (garywilken@me.com); Gene Therriault (genet@gci.net); Jeffrey J Cook (jeff.cook@fhr.com); John Binkley (jbinkley@alaska.net); Michael K. Henry; Mike Kelly (representative_mike_kelly@legis.state.ak.us); rwien@florcraft.nu; Tim Beck (tbeck@ptialaska.net); Tim Beck (tbeck@ptialaska.net); 'Bill Sackinger'; 'Chris Storhok (cstorhok@co.fairbanks.ak.us)'; 'Dave Hoffman'; DeLaina Storhok; 'Doug Smith'; 'Frank Abegg'; Jim Dodson; 'Jim Whitaker (jwhitaker@acsalaska.net)'; 'Luke Hopkins

(mayor@co.fairbanks.ak.us); 'Paul M Park'; Paul Martz; 'Paul Metz (ffpam@uaf.edu)'; 'William Sackinger'; 'Amy Cook (acook@carlile.biz)'; 'Bob Shefchik'; 'Carol E. Lewis (celewis@alaska.edu)'; 'Cynthia Henry (hops@gci.net)'; 'Damian Thomas (damian_ak@hotmail.com)'; 'Dan Britton (dwbritton@fngas.com)'; 'Dan Gavora (dgavora@doyonutilities.com)'; 'Jack Hebert (jack@cchrc.org)'; 'Jesse VanderZanden (jesse.vanderzanden@alaska.gov)'; 'Kathryn Dodge (kdodge@co.fairbanks.ak.us)'; 'Luke Hopkins'; 'Matt Want'; 'Steve Lundgren (slundgren@denalstatebank.com)'; 'Terry Strle'; 'Tony Johansen'; (scott.v.bell@gmail.com); 'Buzz Otis'; 'Buzz Otis'; James M. Collins; Jerry Sadler (AERINC4@alaska.net); 'Jim Haselberger (jimh@alaskatent.com)'; Jim Johnsen (johnsenj@doyon.com); Joe Faulhaber (hellojoe02@gmail.com); 'Paul McCarthy'; 'Paul Robinson'; Ralph Seekins; Reinhard Neuhauser; Tim Cerny (tcerny@fdifairbanks.com)

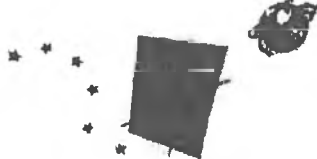
Subject: Document1

I have attached, for your information, an article I copied from the Alaska Dispatch. After reading this article I hope you question, as I do, the focus that some of Alaska's political leaders have on building a gas line for the purpose of exporting Alaska gas. State gas revenue is not going to replace the revenue the state receives from oil production. Business as usual is not working.

Jim Dodson

Jim Dodson

President & CEO



FAIRBANKS
Economic Development

907-452-2185

jdodson@investfairbanks.com

www.investfairbanks.com

20.

Revenue Source

Book re: ANS

Production

Decline handout

Revenue Sources Books, Alaska Department of Revenue
Excerpts re: North Slope Production Decline, 1988 - 1994

October 1988 Revenue Sources

"It is important to emphasize that the North Slope producers, while not agreeing on the exact date, have concluded that North Slope production will commence to decline in either FY 89 or FY 90."

Spring 1989 State Revenue Forecast

"Alaskan production is expected to fall to about half its present levels by the later 90's ... Therefore, only a combination of budget cuts, more efficient programs, and new revenues will allow the State to move into the 90s without significant disruptions in public services ..."

Fall 1989 Revenue Sources Book

"The fall in oil production means that the inevitable decline in the huge Prudhoe Bay field has started sooner than we predicted ... This forecast assumes that production from the Prudhoe Bay field will continue to fall steadily, and will drop to less than half its present level in less than 10 years."

"Some observers may believe that exploration will discover another Prudhoe Bay. Prudhoe Bay is the largest oil field in North America, and finding such a 'supergiant' is extremely rare."

"The State of Alaska is standing on a precipice. Only a combination of budget cuts, more efficient programs, and new revenues will keep the State from falling a long way ..."

"The decline in production from the Prudhoe Bay field is a central issue for Alaska ... The decline in Prudhoe Bay production is now expected to be much more rapid than assumed in our Spring forecast."

Spring 1990 Revenue Sources Book

"The bad news for Alaska's revenue outlook is that oil production is falling (the second year in a row) and Trans Alaska Pipeline tariffs are going up. Expensive repairs to the pipeline will raise the cost of shipping Alaskan oil and reduce the wellhead value on which our taxes and royalties are figured ... We need to confront the fact that Alaska's oil production in a dozen years will be one-fourth the present level. Unless production increases four fold, or the price for oil quadruples (to \$80), we are at the precipice ... The decline in production from the Prudhoe Bay field is a central issue for Alaska."

Fall 1990 Revenue Sources Book

"The success of recent projects to increase production from all existing North Slope oil fields, and the prospect of new production, will postpone serious decline in Alaska production for a couple more years. However, barring discovery of new reserves, production will begin to fall dramatically. This forecast assumes that production will fall to half of current levels within 12 years ... Statewide oil production is expected to decline 10% to 12% through 1995 and 50% by the year 2003."

Fall 1991 Revenue Sources Book

"Oil production from the North Slope continues to decline as the mammoth Prudhoe Bay field and the other smaller fields are depleted. This problem is not going away and the farther the decline curve is projected into the future, the bigger the problem becomes."

Spring 1992 Revenue Sources Book

"The long-term revenue outlook is dominated by the depletion of petroleum reserves of the Prudhoe Bay oil field ... Despite the start of the irreversible decline at the Prudhoe Bay field this year, continued success in reservoir management in all fields will hold statewide production decline throughout fiscal year 1995 to less than 9% total (3% per year)."

Fall 1993 Revenue Sources Book

"Summer maintenance on the North Slope, installation of the GHX-2 facility at Prudhoe Bay and the start-up of the West Beach, Point McIntyre and North Prudhoe Bay State fields have slowed the decline of ANS production ... Field enhancement, the addition of three new North Slope satellite oil fields and the prospect of a commercial find in Cook Inlet should keep the decline in Alaska production from four to five percent per year through 1999."

Spring 1994 Revenue Sources Book

"The Prudhoe Bay field, which accounts for two-thirds of Alaska statewide production, is in irreversible decline."

21.

**"With Prudhoe
Bay in Decline,
What's Next for
Alaska?"**

Aug. 3, 1992

OIL & GAS JOURNAL

International Petroleum News and Technology

WITH PRUDHOE BAY IN DECLINE, WHAT'S NEXT FOR ALASKA?

By James M. Davis (Senior Vice President for Exploration and Land) & Jerry R. Pollock (Manager, Prudhoe Bay Engineering) of ARCO Alaska, Inc.

August 3, 1992

Anchorage

Almost every day, it seems, someone is mentioning Prudhoe Bay—its development activities, the direction of its oil production, and more recently its decline rate.

Almost as frequently, someone is mentioning the number of companies abandoning exploration in Alaska.

The state faces a double-edged dilemma: decline of its most important oil field and a diminished effort to find a replacement for the lost production.

ARCO has seen the Prudhoe Bay decline coming for some time and has been planning for it. We have reduced staff, and ARCO and BP Exploration are finding cost-effective ways to work more closely together through such vehicles as shared services.

At the same time, ARCO is continuing its high level of Alaskan exploration.

This article will assess the future of Prudhoe Bay from a technical perspective, review ARCO's exploration plans for Alaska, and suggest what the state can do to encourage other companies to invest in this crucial producing region and exploratory frontier.

THE PRUDHOE DECLINE

By any definition, Prudhoe Bay is declining and will continue to decline.

Our calculations show the field decline rate will average 8-10%/year through the year 2000. Year to year the rate may be more or less than 8-10% because projects such as the GHX-2 gas handling facility will serve to offset the field's natural decline.

To accountants, Prudhoe decline began during 1988 when the field was no longer able to make its maximum allowable rate of 1.5 million b/d of oil. To engineers, the decline began long before that.

When Prudhoe first met its maximum allowable production rate in 1979, it took only 218 wells to produce 1.5 million b/d. By 1988 it took 916 wells -- some producers, some injectors -- to produce the same amount. Well production had declined by a factor of four, dropping from 7,000 b/d/well initially to less than 1,700 b/d/well.

In other words, to keep production up, the number of wells had to be quadrupled. Between 1979 and 1988, 700 wells were drilled at a cost, including related facilities, of more than \$3.5 billion.

Facility and basic infrastructure improvements also were made, costing about \$9 billion. This includes installation of the central gas facility and the seawater treatment plant.

These outlays were in addition to an original \$9 billion invested to put Prudhoe Bay on line. Investment to date in Prudhoe totals about \$22 billion.

Investment in new wells, facilities, and infrastructure enabled Prudhoe to produce at 1.5 million b/d of oil for 9 years -- 3 years longer than originally forecast, longer than anyone ever thought possible.

FINITE RESERVES

Unfortunately, adding more wells can't keep the oil production rate up forever. We're already past the point where drilling can stave off a falling oil rate. Oil reserves are finite.

Today it takes 1,100 wells, each averaging about 1,200 b/d, to make the current field rate of 1.3 million b/d of oil.

The cost of drilling these wells has not gone down, but production benefits have. That's why we are trying so hard to control costs and to recognize and account for those costs we cannot control -- such as taxes and regulatory compliance costs. All additional costs hurt future investment opportunities.

Water production, effectively nil for the first few years of field life, now exceeds 1 million b/d. By 2000, water production is expected to exceed 1.5 million b/d.

Gas production is more than three times what it was initially -- currently about 5.2 bscfd. GHX-1 helped raise the field gas handling capacity to that level. Following installation of GHX-2 in 1994, gas production will increase again, to 7.5 bscfd, enabling us to produce the higher GOR wells.

But there is an economic limit to adding facilities.

As the field matures, the production facilities reach their maximum capacities to handle produced water and gas. Wells with falling oil rates and increasing produced water or gas volumes have to be shut-in. Total field oil production drops.

The number of wells is going up, and the volumes of water and gas that have to be handled from each well are also going up. These are the three main items that tend to drive costs up in Prudhoe Bay.

Though field oil rates continue to fall, costs per barrel -- including capital investments and operating expenses -- keep on rising.

Profitability is being eroded by the effects of declining production. We are seeing more projects at Prudhoe that have marginal economic returns. We need to find more cost-effective means to do our work so we can keep investing in new projects to develop new reserves.

That's why we're sharing field services with our co-operator, BP Exploration, and why we've entered into an era of partnering with vendors and contractors.

INVESTMENT PLANS

Future development investments fall broadly into four categories: enhancing productivity of existing wells, drilling additional development wells, expanding existing facilities to handle increasing amounts of produced water and gas, and improving and implementing technologies to enhance oil recovery.

Of the field's total production rate, about 85,000 b/d of oil results from ongoing remedial well work.

Each year for the next 5 years we plan 50 fracture jobs, 300 chemical treatments, 200 nonrig workovers, 85 rig workovers, and 35 sidetrack replacement wells. Well work is expected to cost about \$600,000/day for the next 5 years -- about \$1 billion for the period.

In development drilling, 250-400 additional wells are planned for Prudhoe Bay field through the end of this decade, costing a total of \$1-1.5 billion. Currently there are three development drilling rigs working in Prudhoe, and we hope to sustain this level of activity through 2000.

This level of development drilling is expected to increase field recovery by about 175 million bbl.

Prudhoe Bay field's first major gas handling expansion project, GHX-1, was installed in late 1990. By yearend 1990, GHX-1 was contributing about 100,000 b/d of oil to the field rate. Additional GHX-1 gas compressor upgrades remain in progress.

Field production did not increase 100,000 b/d in 1991 when compared with 1990. The field rate was essentially flat year to year. GHX-1 with its 100,000 b/d additional rate merely offset the decline from the rest of the field.

Our largest project under way is the second major phase of gas handling expansion, called GHX-2.

This \$1.4 billion project enables wells that are producing high gas volumes to continue producing oil. In addition, GHX-2's gas handling process is designed to recover natural gas liquids from produced gas. The NGLs will be shipped by the pipeline and sold along with the oil.

GHX-2 is also expected to contribute 100,000 b/d of production by 1995, again helping to offset the 8-10%/year field decline.

Taken together, GHX-1 and GHX-2 are expected to boost field recovery by about 800 million bbl over the life of the field. Work on GHX-2 has begun at Prudhoe Bay.

EOR work received a boost recently when the Alaska Oil and Gas Conservation Commission approved the operators' request to double what already is the world's largest miscible injection EOR project. Planned expansions will increase recovery by 150-220 million bbl. Facility modifications being implemented with GHX-2 are an integral part of these projects.

These four projects -- well work, drilling, GHX-2, and EOR -- total \$3.54 billion in planned investments during the next several years. We hope that more projects can be added to this list over time.

FUTURE PRODUCTION

Prudhoe Bay was found with 22 billion bbl of oil in place. Recovery of 9.6 billion bbl of oil from the field was initially forecast back in 1977.

However, continued development has increased expected recovery to more than 12 billion bbl of oil.

We've already produced about 7.5 billion bbl of oil, leaving about 4.5 billion bbl of reserves and 10 billion bbl in place as a target for the future, an incentive for new projects and improving technology. Still, investment decisions are getting tougher.

With the reality of Prudhoe's declining production, sustaining Alaska's oil production and revenues will require opening up new fields and new areas for exploration.

New reserves need to be brought on line on the North Slope if the TransAlaska Pipeline's rate is to be maintained.

New fields would help Prudhoe Bay by lowering transportation costs from where they otherwise would be -- and perhaps even extend Prudhoe's productive life.

EXPLORATION OVERVIEW

For these reasons, and in view of the fact that more than 85% of the state's income comes from royalties and taxes on oil production, it is disturbing to see that the Alaskan rig count ended 1991 at its lowest level in 17 years. There is not much promise of improvement in 1992.

If Alaska and the Alaskan oil industry are to remain healthy over the long term, we must continue to explore for new sources of oil -- and we must be successful.

In terms of exploration, ARCO plans to spend \$600 million in Alaska during the next 5 years. In 1992, we expect to see 15-25 exploration wells drilled in the state, with ARCO participating in 75-80% of them.

In Cook Inlet last year, ARCO and its partner Phillips Petroleum Co. announced an oil discovery at the Sunfish prospect. A jack up rig is drilling a follow-up well to further evaluate the discovery.

Last winter ARCO operated five drilling rigs on exploration prospects, the most activity of any company in Alaska.

This included the BLT well north of Anchorage, which found natural gas but did not flow at commercial rates -- a real disappointment to us. The BLT was a unique well for Alaska in that the mineral ownership included private land.

The local economy benefitted from 37 local people who were employed at the rig site and more than \$1.5 million spent locally for services and supplies.

ARCO and partners also drilled the Cabot prospect in federal waters off Barrow, the third western Beaufort Sea exploratory well.

We recently completed a four well exploration program in the Colville area, west of Kuparuk on the North Slope.

ARCO has completed negotiations in putting together a group of companies to drill an exploratory well this summer at the Kuvlum prospect in the eastern Beaufort. ARCO will hold the largest interest in the group of six companies.

ARCO is the only company active in the interior basins. We have an agreement with Doyon in the Nations River basin, near the Canadian border, where we have completed extensive geological studies and seismic and other geophysical studies.

We are researching new drilling systems for work in this area that are less costly and have less impact on the environment. We are looking for a partner to help us drill the prospects that have been identified.

This exploratory activity is aimed at preserving ARCO's future in Alaska.

COMPETITION NEEDED

Other oil companies, including many that do not have production in Alaska, have announced in recent months they are giving up their exploration efforts in the state and intend to invest their exploration dollars in foreign countries.

This is disturbing news because it is in both the state's interest and ARCO's interest that Alaska maintain an aggressive exploration program, with a vigorous service industry supporting it.

Why does ARCO want competition in Alaska?

First: Given the high cost of exploration and the low chance of commercial success, we need partners to share the risk. Onshore, it costs \$5-10 million to drill a single well. Offshore, the cost can range from \$20 million to \$50 million or more.

The only way to stay within a reasonable budget and still participate in a significant number of wells is to team up with other companies.

Second: Because of the way land is traditionally leased, in relatively small blocks, companies must form partnerships to create a leasehold large enough to justify an exploratory well.

While we need such partnerships, coming to agreement on when a well will be drilled, and how costs and production will be shared, is difficult, especially if the companies have differing views of Alaska.

Third: A single company cannot alone support a viable service industry.

Now to a key question: Why is Alaska, like the U.S. in general, losing the battle for exploration capital?

Uncertainty over taxation and regulation is one of the reasons the industry is exploring less in Alaska and the Lower 48 and investing those dollars overseas.

Lack of access to land -- in particular large blocks of land -- is another.

And in Alaska the lack of exploration success on the Outer Continental Shelf is yet another reason.

Industry has spent \$10 billion exploring the Alaskan OCS through 1990, including 75 dry holes. More than \$6.5 billion of that went for lease sale bonuses and rentals. Only \$3 billion went for actual drilling costs.

The majority of companies conducting Alaskan OCS exploration have had little participation in onshore drilling.

Given the record of dry holes offshore, it should come as no surprise that these companies are reassessing their positions and looking elsewhere.

AIRCO'S PLANS

Why isn't ARCO taking its exploration dollars out of the state?

Two good reasons: We are exploring onshore as well as offshore. And we have had exploration success.

Since the late 1980s we have had an exploration program balanced between the onshore and the offshore. With the lack of success in the OCS, ARCO, unlike some of its competitors, was able to easily redirect efforts onshore.

Over the past 4 years, ARCO has invested more than 250 man-years in basic regional studies of Alaska. This summer marks the 37th consecutive year that ARCO has had geologic field parties in Alaska. No other company matches that record.

We believe these investments give us an edge over our competitors. This understanding has led us to aggressively invest in both state and federal acreage.

In addition, our people live and work in Alaska and are able to communicate routinely and in a timely way with state agencies. But the most important reason ARCO maintains an aggressive exploration program in Alaska is that ARCO has had exploration success.

We made the discovery at Swanson River in 1957 that helped achieve statehood for Alaska. We also discovered the Prudhoe Bay, Kuparuk River, Lisburne, and Point McIntyre fields. Last fall we announced the Sunfish discovery in Cook Inlet.

We believe that Alaska offers a resource base that is as prospective as anywhere in the world, especially in view of continually evolving technology. If we didn't, we would not be Alaska's most active explorer.

COMPETING COUNTRIES

But Alaska competes with countries that offer a business environment compatible with the exploration process and that encourage exploration.

Those countries grant concessions on large contiguous blocks of acreage. Exploration rights are valid for a period appropriate to the process. Stipulations are known up front, including terms of operations, environmental requirements, and development requirements.

In addition, partnerships are known ahead of time as they are developed prior to joint bidding for the concessions.

Of course there are work requirements. But no company bids on these types of concessions unless it plans to conduct activities.

So what can the state do to reverse the trend to overseas investment?

For one thing, the state must be a strong advocate of a stable and truly area-wide OCS lease sale program in Alaska.

The state should also support the opening of the Arctic National Wildlife Refuge Coastal Plain -- not only for the bonuses it would receive but also because a good discovery in ANWR would also justify construction of a pipeline to connect with the TransAlaska Pipeline and perhaps open up added opportunities.

The state also must do more to entice explorers back to Alaska and onshore. While the state has done a good job in allowing access to state lands and has provided reasonable stability in administrative processes, there is room for improvement.

We see a continual escalation of permitting requirements. Each additional permit is more stringent in its stipulations.

The value of this escalation is doubtful, both from an environmental perspective and certainly from a cost/benefit viewpoint. As an example, it recently took 3 years to permit a new drill pad in Kuparuk field.

There is also opportunity to streamline the permitting process. More than time is lost in the maze of paperwork. ARCO employs 35 people full time, and others spend part of their time to handle the permits required to drill about a dozen exploratory wells each year, as well as for development projects. If some of those people could be redirected to identifying exploration prospects, we could have a much better chance of finding the reserves that both Alaska and ARCO need.

EXPLORATION UNITS

Another way the state could help is in actively encouraging the formation of exploration units.

The exploration unit concept is a powerful way for the state to level the playing field in competition with other countries. It allows the combining of tracts with different expiration dates and different owners into a unit held together beyond individual lease expiration dates, as long as expected work is done.

We see the current process of forming units becoming more burdensome. What should take a week for administrative review by the state is now taking many months.

We are happy to hear that the state is now considering a form of the concession arrangement. The state and native corporations could and should work together in the interior basins to offer large blocks of land for exploration.

The completion of the state's land selections, which the Department of Natural Resources has identified as a top priority, offers a unique opportunity to aid the exploration process.

Lands can be selected to preserve access to prospective oil and gas resources and for transportation corridors for pipelines, if exploration is successful.

It would be difficult to restore Alaska to previous high levels of exploration activity. But with these improvements, the state can at least stem the tide of retreating exploration dollars.

Such new life to Alaskan exploration is essential as production from the old giant Prudhoe Bay continues its long, steady decline.

Copyright 1992 Oil & Gas Journal. All Rights Reserved.

To access this Article, go to:

<http://www.ogj.com/content/ogj/en/articles/print/volume-90/issue-31/in-this-issue/general-interest/with-prudhoe-bay-in-decline-what39s-next-for-alaska.html>

22.

Testimony to
U.S. Senate by
Kevin Banks,
Director,
Division of Oil
& Gas
May 10, 2011

S. HRG. 112-30

**NEW DEVELOPMENTS IN UPSTREAM OIL AND
GAS TECHNOLOGIES**

HEARING
BEFORE THE
**COMMITTEE ON
ENERGY AND NATURAL RESOURCES**
UNITED STATES SENATE
ONE HUNDRED TWELFTH CONGRESS

FIRST SESSION

TO

RECEIVE TESTIMONY ON NEW DEVELOPMENTS IN UPSTREAM OIL AND
GAS TECHNOLOGIES

MAY 10, 2011



Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE

67-090 PDF

WASHINGTON : 2011

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512-1800; DC area (202) 512-1800
Fax: (202) 512-2104 Mail: Stop IDCC, Washington, DC 20402-0001

APPENDIXES

APPENDIX I

Responses to Additional Questions

RESPONSE OF KEVIN R. BANKS TO QUESTION FROM SENATOR BINGAMAN

Question 1. As a regulator for Alaska—do you feel that there are adequate safety and oil spill prevention and mitigation technologies available for E&P operators and drillers in the advent that a blowout or some other type of oil spill should occur onshore in arctic areas?

Answer. Since the Exxon Valdez oil spill, oil spill response planning and equipment staging and availability have improved dramatically. As a direct result of the State's oil spill response program outlined in AS 46.04.200, the Alaska Department of Environmental Conservation, (ADEC) develops, annually reviews, and revises, as necessary, the State Oil and Hazardous Substance Contingency Plans (Unified Plan and Subarea Contingency Plans). These plans address all oil and gas related contingency planning activity in the state. The Unified plan is a coordinated and cooperative effort by government agencies and was written jointly by the Alaska Department of Environmental Conservation, the U.S. Coast Guard and the U.S. Environmental Protection Agency. The Unified Plan is then divided into 10 Subarea Contingency Plans (SCP) that concentrate on issues and provisions specific to that region or subarea.

As identified in the Unified Plan, ADEC, as the State of Alaska's lead agency for responses to oil and hazardous substance spills, has developed a network of response equipment packages positioned in at-risk areas throughout the state.

ADEC also requires that all municipalities, operators of facilities and private owners be able to respond to spills and must itemize all spill response equipment required in their respective spill response contingency plans. Through the Unified Plan and the Subarea Contingency Plans, the ADEC has a comprehensive list of spill response equipment available to be deployed throughout the state.

In the North Slope subarea specifically, BPXA, ConocoPhillips Alaska and other companies operating in the North Slope oilfields have a substantial amount of spill response equipment, as identified in their respective contingency plans. In the event of a spill in this area, the industry spill response cooperative, Alaska Clean Seas, would provide much of the required response equipment and personnel. Industry equipment would also be utilized, especially when the company is identified as the responsible party for the spill.

While appropriate response equipment is staged throughout Alaska and the North Slope, due to its vastness and sometimes extreme weather conditions, there is always the logistical challenge of getting the right piece of equipment to the right location at the right time.

RESPONSES OF KEVIN R. BANKS TO QUESTIONS FROM SENATOR MURKOWSKI

Question 1. As you are aware, there has been a strong effort to find new sources of oil to keep the Trans-Alaska Pipeline System operating at sound levels. With Prudhoe Bay, Alaska has a super-enhanced oil recovery operation because so much gas is being re-injected into that huge field.

a. Can you address how Prudhoe was originally estimated to be maybe one third its size or less, and how much greater the recovery has been as technology has advanced?

Answer. A reference to Alaska Department of Natural Resources (DNR) report from January 1982—TAPS start up was June 1977—estimated that the Prudhoe

Bay, Sadlerochit reservoir in 1980 contained 7.8 billion barrels of recoverable oil. (DNR January 1982. Historical and Projected Oil and Gas Consumption) The most recent report published by DNR says that by the end of 2009, the Prudhoe Bay Unit produced 12.6 billion barrels of oil and still had remaining reserves of 2.4 billion—a total of 15 billion (DNR 2010 Annual Report). Total production to date from all of the fields on the North Slope exceeds 16 billion barrels.

This growth of the Prudhoe Bay field over time can be attributed to two causes: technological advances in recovery methods, and the fact that as drilling progresses, additional reserves were added with discovery and development of over-and underlying horizons, and around the periphery of the field.

Question 1b. Can you describe the progress that has been made, through the use of modern technologies, in shrinking the footprint for drilling areas, roads, and other facilities?

Answer. In my written submission to the committee I provided several examples that show how the drilling technologies, including especially the use of extended reach drilling has significantly reduced the size of drill sites on the surface and the number of drill sites required to reach the oil reservoirs underground. To illustrate the point, one of the earliest drill sites built in the in the 1970's at Prudhoe Bay (DS-1), covered 65 acres of tundra. Well spacing, the distance between the well heads on the site, was 160 feet. Each early Prudhoe Bay drill site could accommodate 25-30 wells. These wells could be deviated from vertical only about a mile.

The Alpine field (the Colville River Unit) is a recent example of how far the technology has advanced to reduce the industry's onshore footprint. The typical Alpine drill site is only 13 acres and supports 54 wells. Extended reach drilling means that the wells can reach four miles from vertical and intercept 50 square miles of the reservoir from a single location on the surface. Alpine is also the first oil field on the North Slope that is not supported by a year-round road. During the winter, the operator builds an ice road to the central Alpine facility and equipment is staged there for summer work. Operations during the summer months are supported by air.

Question 2. Is it fair to say that the technologies born in Alaska have grown out of necessity? In other words, has the combination of strict environmental laws and the economic considerations of not wanting to drag many new rigs and new equipment that great of a distance caused a natural inclination to make the most of seismic data, shrink footprints, reach further from one pad, and try to squeeze as much from one well as possible?

Answer. Yes, it is fair to say that these technologies have been born out of necessity. We would add that the driving forces behind technological advancements reflect regulatory insistence and industry commitment to maximize economic benefit and recovery while minimizing the development footprint. It has been necessary to engineer the development of smaller fields at reduced costs, adopting more innovations to increase recovery efficiency, both at the level of individual wells and entire fields.

The fact that the in-place oil volumes in several of the North Slope's largest fields (Prudhoe Bay, Kuparuk, and the various heavy oil reservoirs) are so enormous means that the economic return associated with increasing total recovery by even 1-2% is worth major investments in new technologies that make that additional recovery feasible. On the other hand, many of the North Slope's smaller fields face major economic challenges that were mitigated in large part by technological advances and efficiencies that originated in the giant fields nearby.

The following are examples of some of the many technologies that have been created or refined in developing the major oil fields of the North Slope:

Technology	Impact
Extended reach drilling	Dramatically fewer surface pads needed to access reservoir.
Horizontal/designer wells	Improves reservoir drainage relative to vertical wells.
Coiled tubing drilling	Reduces noise, fuel consumption, emissions, cost, surface area.
Multi-lateral drilling	Drains more of reservoir per surface well location.
Grind-and-inject	Zero surface discharge of drilling wastes.
Reservoir modeling	Models oil-in-place, drainage, injection, pressure, etc. in 3-D over time.
WAG, MWAG, MI, etc.	Enhanced oil recovery methods, beyond simple waterflooding.
Gas cap water injection	Stabilizes reservoir pressure, increasing oil recovery.
Gravity survey surveillance	Monitors movement of reservoir fluids over time.
3-D and 4-D seismic	Sharper imaging of reservoir compartments, fluid movements, etc..
BrightWater EOR treatments	Improves waterflood efficiency by blocking off thief zones.
Low-salinity water injection	Liberates oil molecules bound to clay particles in the reservoir rock.
Heavy oil extraction methods	Several different methods in development to enhance recovery, depending on reservoir temperature, oil viscosity, etc..

a. Would the other witnesses like to comment on the Alaska experience and how it's allowed operations elsewhere to advance?

Question 3. Some have suggested that the Trans-Alaska Pipeline System is perfectly capable of operating soundly until mid-century, even with no access to federally controlled oil deposits. As one of the State's leading oil experts, can you describe the throughput decline of TAPS and what it will take to maintain its operation through that point in the future?

Answer. TAPS was originally designed to move about 1.5 million barrels per day. Throughput peaked at 2.03 million barrels per day in 1988—a rate achievable with the application of drag reducing agents and other improvements. Throughput has declined in all but two years since 1988. Current throughput is about 0.6 million barrels per day. Most forecasts show continued decline into the future.

The TAPS line has already begun to be impacted by lower throughput. During the shut-down in January 2011 (leak at Pump Station No. 1), there was concern about being able to restart the line due to the temperature. TAPS will have some material operational issues as the flow rate reaches 0.3 million barrels per day. The operational issues are primarily related to the temperature of the crude as it moves through the pipeline. With less flow and without mitigating investments, the temperature may fall below 32 F. Lower temperatures may allow ice to form inside the pipeline that could damage equipment and cause possible frost heaving on buried sections of the pipeline route. Lower temperatures will also lead to more build-up of wax on the inside of the pipeline, and increase the viscosity of the crude moving in TAPS.

More than 99% of TAPS throughput comes from fields on State or Native lands or from State waters. Production from Federal lands and the OCS today amounts to less than two thousand barrels per day.

With the exception of development of the heavy oil resources known to exist around the Prudhoe Bay, Kuparuk, and Milne Point fields, and potential resource plays (like the Bakken in North Dakota) that may exist on the North Slope on State controlled lands, the natural field declines cannot be replaced without access to production from Federal lands and the OCS. There are no known conventional resources on State or Native lands that are likely sufficient to replace the decline in the existing production rates.

Conoco-Phillips and Anadarko want to expand the Alpine field by developing a new drill site (CD-5). New production would come from State, Native, and Federal lands (~60 miles west of TAPS). This development is on hold awaiting permits from the Corps of Engineers to allow construction of a bridge over the Colville River. The permit was first requested in 2005. Development in the National Petroleum Reserve Alaska (NPRRA) can only proceed once the Alpine bridge over the Colville River is complete. Thankfully, the Administration has proposed having lease sales in the NPRRA annually. We hope that these sales will be accompanied by a willingness of federal agencies to allow permits for development (e.g., CD-5 project) and that lands with high resource potential (e.g., north of Teshekpuk Lake) can be made available for leasing with appropriate environmental safeguards.

There are current plans to develop an oil and gas field on State lands at Point Thomson (Miles east of TAPS). Development at Point Thomson has also been delayed due to Corps of Engineers permitting issues. Development of resources at Point Thomson would extend the feeder lines for TAPS about 30 miles east of the Badami field. This would lessen development costs and could lead to development in this relatively unexplored area. It is also at the boundary to ANWR and the 1002 area.

Question 4. Can you talk about the new technologies we're hearing about in terms of allowing for development of an area where the law doesn't currently allow for conventional access? In other words, are there applications for this technology that would provide an opportunity to extract resources from the 1002 area subsurface without having any permanent or significant impacts on the surface area?

Answer. Although it remains unclear how far, if at all, the Sourdough or Pt. Thomson reservoirs discovered on State leases near the Canning River delta might extend beneath the 1002 area, there is the potential that extended reach drilling could at least partially develop these reservoirs. Without more detailed subsurface data on these and other prospects along ANWR's western border and along the coastline adjacent to state submerged waters, it will not be possible to accurately evaluate how much of these reservoirs would benefit from extended reach drilling techniques. Three-dimensional seismic acquisition and near-vertical exploration and delineation drilling would have to occur inside the 1002 area. These activities can be conducted in the winter with zero or minimal permanent surface impact. Allowing these activities would help answer the question of whether how much oil extended-reach production wells drilled from outside ANWR would be economically viable.

RESPONSES OF THOMAS DAVIS TO QUESTIONS FROM SENATOR BINGAMAN

Question 1. Are there recent advances that will help reduce the footprint of seismic activities in environmentally sensitive areas, both in terms of active seismic data acquisition and passive?

Answer. Yes, major advances have occurred with the advent of wireless seismic technology and increased sensitivity and numbers of seismic sensors. Wireless recording systems now leave only human footprints in terms of placement of recording systems. The weight and power consumption of these wireless recorders is such that a person can carry several devices and plant them in environmentally sensitive areas provided they are accessible to humans. There has been recent experimentation with dropping these devices from helicopters as well, but retrieval remains an issue. These devices can record up to a month without being serviced. They contain GPS receivers and the clocks in the devices are synchronized and are highly accurate. The devices can be placed in active recording mode to record generated sources from hydraulic vibrators, weigh drops, or dynamite, for example. They can also be placed in continuous recording mode when the intention is to record passively the natural seismicity or induced seismicity, for example, from drilling or completion operations.

Question 2. Have there been any recent advances in downhole seismic instrumentation that allows an operator to see further into the formation from the wellbore to areas that may not have been adequately imaged using conventional 2-or 3-Dimensional seismic data?

a) Or to areas that cannot be accessed at the surface due to environmental sensitivities?

b) In other words, is there a borehole version of conventional seismic?

Answer. Yes, major advances have occurred in downhole seismic recording technology as well. We have developed capabilities to record with borehole arrays of receivers spanning different intervals and within different wells. The closer we can

23.

**Alaska Economic
Trends:
"Alaska's Oil
Industry"
Sept. 2008**

A black and white photograph of an industrial oil rig interior. Three workers wearing hard hats and work clothes are standing on a metal grating floor, looking towards a large piece of machinery. The background is filled with complex metal structures, pipes, and cables. The overall scene is industrial and technical.

ALASKA ECONOMIC TRENDS

SEPTEMBER 2008

Alaska's Oil Industry

WHAT'S INSIDE

Employment Scene

Two economic indicators, two different storylines



ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT

Sarah Palin, Governor
Commissioner Click Bishop

ALASKA ECONOMIC TRENDS



ALASKA DEPARTMENT OF LABOR
& WORKFORCE DEVELOPMENT

Sarah Palin, Governor of Alaska
Commissioner Click Bishop

September 2008
Volume 28
Number 9
ISSN 0160-3345

Brynn Keith, Chief
Research and Analysis

Susan Erben, Editor
Sam Dapceвич, Graphic Artist

To contact *Trends* authors
or request a free subscription, email
trends@alaska.gov or call (907)
465-4500. *Trends* is on the Web at
laborstats.alaska.gov.

To contact us for more
information, a free
subscription, mailing list changes
or back copies, email trends@
alaska.gov or call
(907) 465-4500.

Alaska Economic Trends is a
monthly publication dealing
with a wide variety of economic-
related issues in the state. Its
purpose is to inform the public
about those issues.

Alaska Economic Trends is
funded by the Employment
Security Division and is published
by the Alaska Department
of Labor and Workforce
Development.

Alaska Economic Trends is
printed and distributed by Assets,
Inc., a vocational training and
employment program, at a cost
of \$1.16 per copy.

Material in this publication is
public information, and, with
appropriate credit, may be
reproduced without permission.

Cover: Workers are shown in
August on Pioneer Natural
Resources' Nabors Rig 19AC
in the Beaufort Sea, five miles
from shore in about five feet of
water. The rig is part of Pioneer's
Oooguruk project, which entailed
building a gravel island, according
to Pioneer officials. The company,
with its minor partner, Eni Petro-
leum, made North Slope history
when it finished the \$500 million-
plus project in June. That made
Pioneer, whose headquarters are
in Dallas, the first independent oil
company to operate a producing
oil field on the North Slope. Photo:

© Judy Patrick Photography

Alaska's Oil Industry

4

Producing a third less oil but providing
a record number of jobs

Employment Scene

15

Two economic indicators, two different storylines

Trends Authors



Neal Fried, an Alaska
Department of Labor
and Workforce De-
velopment econo-
mist in Anchorage,
specializes in the
Anchorage/Mat-Su
region's employment,
wages and the cost of
living. To reach him,
call (907) 269-4861
or email him at Neal.
Fried@alaska.gov.



Dan Robinson, a
Department of Labor
economist in Juneau,
specializes in state-
wide employment and
wages. To reach him,
call (907) 465-6036
or email him at Dan.
Robinson@alaska.
gov.



Alaska's Resources Provide Economic Opportunity

By Governor Sarah Palin

Alaska's natural resources have painted our past and present economic landscape, and our future depends on wise management of Alaska's resource bounty.

Currently, oil revenues provide 88 percent of the state general fund. Thanks to oil revenues, wise Alaskans created the Permanent Fund that has returned about \$15 billion in dividends to Alaskans.

Energy generates more than a quarter of the state's gross state product and its riches trickle down through every pocket of the state's economy. Yet the energy industry employs only 4 percent of Alaska's workers, even with a 34 percent growth since 2000 to about 12,000 jobs in June 2008.

Most of Alaska's oil jobs are concentrated in the industry's production and management centers. More than half, 58 percent, are employed on the North Slope, followed by 21 percent in Anchorage. Of the remainder, 10 percent are on the Kenai Peninsula, 7 percent in the Fairbanks North Star Borough, 2 percent in Valdez and 2 percent elsewhere in the state.

Last November, with the hard work of our Legislature, we adopted legislation that ensured a fair share of our oil's value for Alaska and Alaskans. With current higher oil prices, the state's revenue from oil taxes could reach \$10 billion to \$14 billion this fiscal year.

Our Legislature recently agreed that we must help Alaska families get through the tough winter ahead by sharing the state's oil resources with a one-time, special payment of \$1,200 to each Alaskan eligible for the 2008 Permanent Fund Dividend.

But our longer-term prosperity will come from a gasline. With the Legislature's Aug. 1 decision to award the Alaska Gasline Inducement Act license to TransCanada, we can finally look ahead to bringing Alaska's natural gas from the North Slope to our homes, businesses and fellow Americans in the Lower 48.

We are one of the most resource-rich regions in the world. Yet, as we take advantage of our tremendous economic opportunities, we must address the large percentage of nonresidents and an emerging workforce skills gap as a high number of workers approach retirement.

The Alaska Department of Labor and Workforce Development's AGIA Training Plan is a roadmap that will help enhance Alaska's existing training programs so that Alaskans are provided opportunities to acquire or upgrade skills in preparation for gasline jobs. This time we won't rely on imported workers.

Strong partnerships are being created – within state government between the Department of Labor, Alaska Department of Education and Early Development and the entire University of Alaska system, along with other training providers, business and industry. Our efforts have resulted in numerous system improvements, including construction academies in a number of communities that train both Alaska youth and adults for jobs in the construction industry, expansion of the allied health and engineering programs at the University of Alaska, and the Alaska Career Ready Program in the Department of Education and Early Development.

We will continue our efforts to fund vocational, career and technical education that begins in our schools, relevant job training and apprenticeship opportunities to mentor new workers, among other critical needs.

Our natural resources – including our human resources – must be responsibly developed to ensure that Alaska's future is in capable hands.

Producing a third less oil but providing a record number of jobs

There's little doubt that the discovery of oil in Prudhoe Bay transformed Alaska's economy far beyond anyone's imagination. With as much as a third of the state's current economic activity somehow tied to oil, it certainly deserves a prominent place on Alaska's economic stage.

Part of the prosperity of Alaska's oil industry is defined by the direct jobs it creates around the state. The number of jobs isn't large, but they're some of the most sought-after jobs in Alaska. They require a highly skilled work force and their wages are the highest in the state. Aside from the lure of big paychecks, oil industry jobs have a bit of romance to them too – the excitement of discovery and the brawny work environment.

All that might partly explain why many Alaskans are relentless in their efforts to create more op-

portunities in the oil industry, whether it's a new discovery, developing the Arctic National Wildlife Refuge or building a gas pipeline. However, this article will focus on past and current employment trends in the industry to explain why its work force reached record levels in 2008, 20 years after oil production peaked.

A relatively small employer with a big roar

Oil revenue makes up 88 percent of the state general fund's unrestricted revenue. The stream from oil revenue could reach \$10 billion to \$14 billion this fiscal year,¹ according to some estimates.

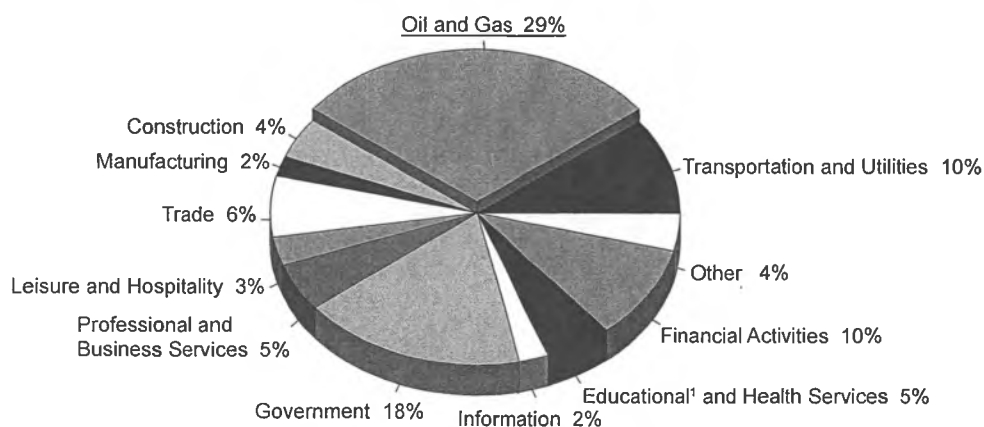
The Alaska Permanent Fund, made possible by oil, has dispersed roughly \$15 billion in dividends since it began giving them in 1982. On a local level, the oil industry is often one of the largest property taxpayers. It generates more than a quarter of the state's gross state product.² (See Exhibit 1.) There are many other ways oil showers down on Alaska's economy as well.

But given all of that, the oil industry still isn't a very big direct employer.

¹ The current fiscal year is fiscal year 2009, which runs from July 1, 2008, to June 30, 2009.

² Gross state product for Alaska is a measurement similar to the gross national product, though it's limited to the production that takes place within the state's borders. It's the sum of value added from all industries in the state.

1 A Large Slice of Alaska's Gross State Product Alaska, 2006



¹Private education only

Source: U.S. Department of Commerce, Bureau of Economic Analysis

In this article, direct oil and gas industry employers are defined as oil producers and oil field service companies – firms such as ASRC Energy Services, ConocoPhillips, CH2M Hill, Doyon Drilling, Peak Oilfield Services Company, Halliburton and Kuukpik Drilling. In technical terms, they fall into three groups: oil and gas extraction, drilling oil and gas wells, and support activities for oil and gas operations.³

Using that relatively narrow definition, oil and gas employment (referred to as oil industry employment for the rest of this article) in June stood at 12,600.

Those jobs represent 4 percent of all wage and salary employment in Alaska, based on 2007 average annual employment numbers. (See Exhibit 2.)

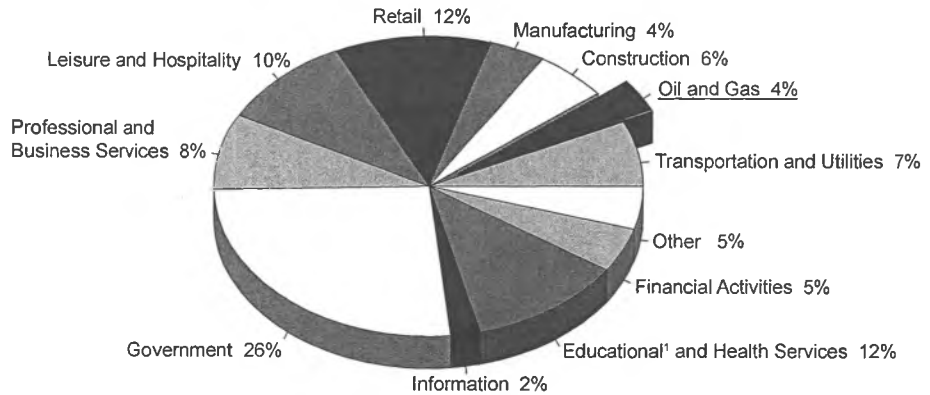
If the narrow oil industry employment definition were broadened to include pipeline transportation – mostly Alyeska Pipeline Service Co. – and petroleum refineries and other downstream operations, the share would be slightly higher.

Because the oil industry's average wage is more than twice the statewide average wage, its payroll impact is more impressive. Alaska's oil industry payroll in 2007 added up to \$1.3 billion, which represented 9 percent of all wage and salary payroll. If pipelines and downstream operations such as refineries are included, the share grows to nearly 11 percent.

Another recent example of the oil industry's influence on wages is reflected in payroll growth. Between 2006 and 2007, the oil industry's payroll grew by 18.8 percent. The total state

³ These are based on the North American Industry Classification System, or NAICS: 211, oil and gas extraction; 213111, drilling oil and gas wells; and 213112, support activities for oil and gas operations.

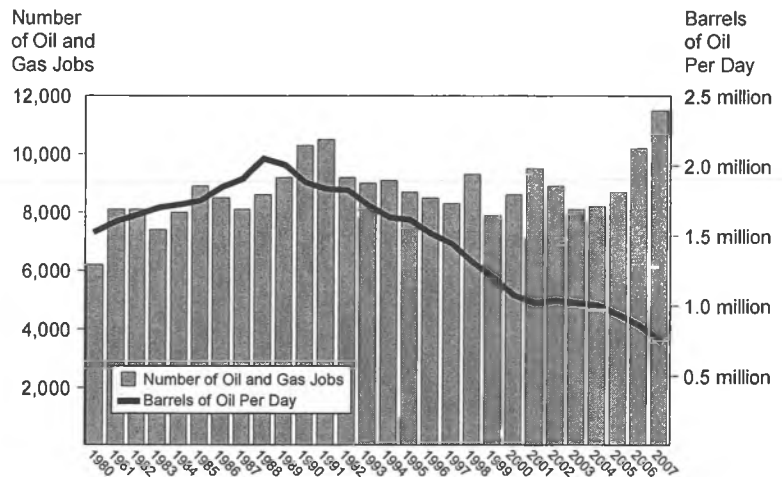
Oil Industry Employment – Small But Mighty **2** Alaska's wage and salary employment, 2007



¹Private education only

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Less Oil Production But More Jobs **3** Alaska, 1980 to 2007



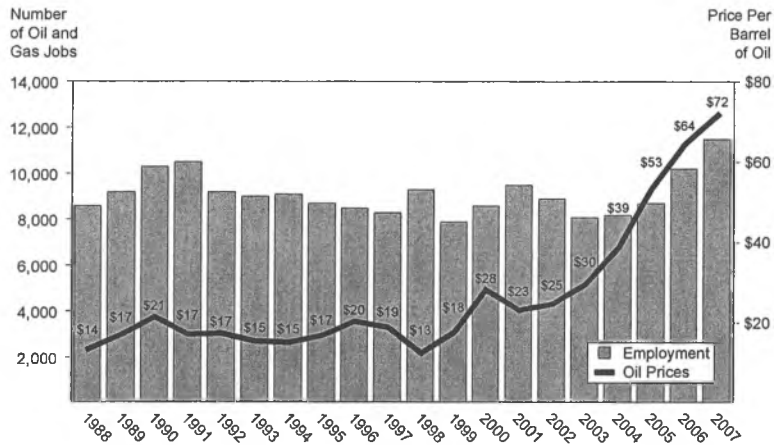
Sources: Alaska Department of Labor and Workforce Development, Research and Analysis Section; and Alaska Department of Revenue, Tax Division

payroll grew by 5.8 percent, the largest increase since 2000.

There are certainly thousands of other direct jobs that service the oil industry but aren't categorized as jobs with oil industry employers. Out of the more than 9,000 jobs in Prudhoe Bay in 2007, more than 1,500 weren't with oil industry employers.

For example, NANA Management Services is one of the larger employers in Prudhoe Bay. Its

4 Oil Prices Impact Industry Employment Alaska, 1988 to 2007



Source: Alaska Department of Revenue, Tax Division; and Alaska Department of Labor and Workforce Development, Research and Analysis Section

employment falls into the four categories of catering, accommodations, facilities management and construction.

Other direct jobs associated with oil industry activity but not categorized as oil industry employment include those for security, transportation, engineering and logistic employers, among others.

Alaska's oil industry employment first peaked in 1991

For most of the past 15 years, Alaska's oil industry employment levels have fluctuated from year to year, with an overarching declining trend accompanied by periods of recovery. (See Exhibit 3.) Oil production peaked in 1988, and shortly after that, oil industry employment peaked in 1991 at 10,700. It wouldn't be until 2006 that the 10,000 barrier would be broken again.

Nationally, oil industry employment had peaked nearly a decade earlier in 1982, a testament at the time to the relative youth of Alaska's oil industry.

Other factors aside from production levels and prices explain the changing size of the oil industry's work force, both nationally and in Alaska. Dramatic improvements in technology in the last

decade have had a powerful effect on employment levels.

Examples include the widespread use of horizontal drilling, ultra extended-reach drilling, 3-D and 4-D seismic surveys, drill bit sensors and other advancements that reduced the number of wells that need to be drilled.

According to the Federal Reserve Bank of Dallas, the national oil and gas industry was the leader in productivity gains throughout the 1990s and continues to be an above-average performer. In other words, the oil industry has been able to perform more work using fewer workers.

Therefore, a decline in employment – nationally and in Alaska – wasn't always tied to a decline in production. The major oil producers also increasingly began using contractors, consultants, outside suppliers and temporary workers to perform many tasks, instead of adding to their permanent staff. That meant that both gains and losses in the industry weren't always captured among the oil industry employers.

One of the largest contractions in Alaska's oil industry work force took place from 1991 to 1992. BP, along with other oil industry employers and contractors, went through a period of major restructuring and consolidation in response to declining oil prices. The downsizing cost the industry 1,300 jobs – a record one-year loss.

Weak oil prices and other factors buffeted the industry again in 1995, when Atlantic Richfield Co. made major cuts to the size of its work force.

By 1998, employment in Alaska's oil patch began to recover with the development of the Alpine, Tarn and Badami fields, the drilling at West Sak, and preliminary work at North Star, Liberty and other fields.

Oil prices plunged from nearly \$19 per barrel in 1997 to \$13 in 1998 and record job losses followed. (See Exhibit 4.) For the first time since 1983, Alaska's oil industry employment fell be-

low 8,000 and the losses reverberated throughout the state's economy.

Finally, in 2000, recovery kicked in and by 2001, oil industry employment reached a 10-year high, nearly 2,000 jobs higher than the industry's nadir in 1999. The near concurrent development of both the Alpine and North Star oil fields were the two major reasons for the upswing in activity. What gave the oil industry's employment numbers some extra loft was the construction of large oil modules in Kenai and Anchorage. Before that, they were built in the Lower 48 or overseas.

The year 2000 marked a historic event: Alaska's largest oil industry employer and discoverer of Prudhoe Bay, Atlantic Richfield, disappeared from the scene when it sold its assets to BP and ConocoPhillips. The sale was a signal to many observers that Alaska's oil industry was moving into its very "mature" stage of development, and – barring any major field discoveries, the opening of ANWR for exploration or construction of a gas line – the industry's employment trajectory was most likely on a permanent downward sloping curve.

Oil industry employment climbs to new record

The following four years appeared to reinforce that view. With most of the work completed on the North Star and Alpine fields, oil industry employment began to fall steeply in 2001 and then hover at the 8,000 level through 2004. What made that peculiar was the fact that the price of oil was recovering nicely from its 2001 low of \$23 a barrel to \$39 in 2004. Even so, it appeared as if Alaska's oil work force was entering an era of stagnation and enduring decline.

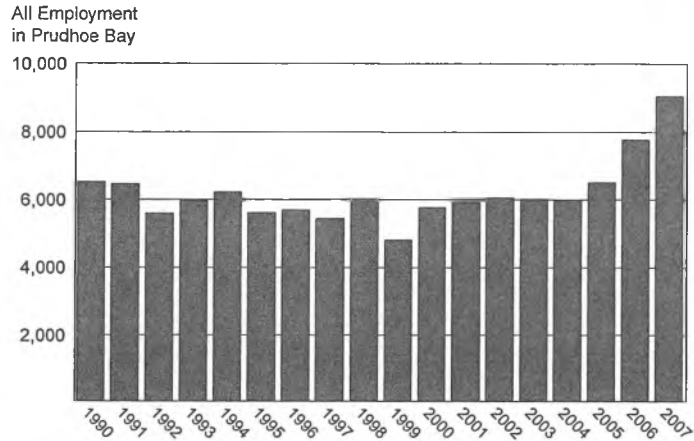
Finally, and possibly due to four years of above-average oil prices that by 2005 had more than doubled from the 2001 low, the oil industry began to stir again in 2005.

Unlike many earlier recoveries, this one wasn't tied to one or two projects. Instead, there were a lot of smaller ones: continued work on heavy oil in West Sak, an increase in the production of

Prudhoe Reaches New Heights

Prudhoe Bay employment, 1990 to 2007

5

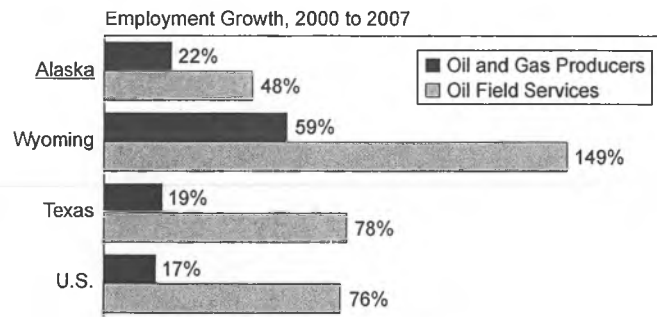


Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Oil and Gas Job Growth

Selected states and the U.S., 2000 to 2007

6



Sources: Alaska Department of Labor and Workforce Development, Research and Analysis Section; Wyoming Department of Employment; and Texas Workforce Commission

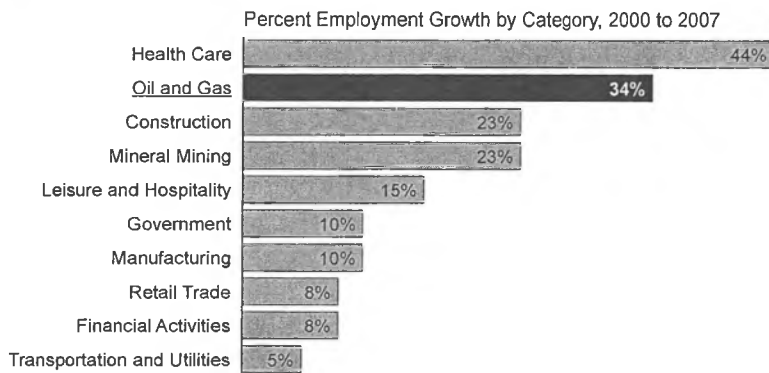
viscous oil, the repair of Prudhoe Bay production wells, work around Alpine, the building of new connecting pipelines, and the continued development of a number of satellite fields.

Then in early 2006, a section of BP's pipeline sprung a leak. It eventually turned out to be the largest oil spill in the North Slope's history.

Soon afterward, BP discovered additional corrosion problems, forcing the company to shut down the pipeline for a short period.

The spill and corrosion led BP to spend more than \$260 million in 2007 and 2008 to replace 16 miles of pipeline in Prudhoe Bay and up-

7 Strong Growth Since 2000 Alaska, 2000 to 2007



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

grade the company's facilities. Undoubtedly, that helped turbo-charge Prudhoe Bay employment numbers in late 2006 and early 2007. (See Exhibit 5.)

In fact, the University of Alaska's statewide construction forecast for 2007 predicted that construction dollars tied to oil industry activity would grow by 30 percent, single-handedly keeping overall statewide construction spending in the black that year.

Oil-related construction represented 38 percent of all construction dollars in 2007, compared to 28 percent in 2004. In a similar vein, the Alaska Department of Revenue estimates that capital expenditures made by the oil industry on the North Slope nearly doubled between 2004 and 2007.

The growing list of independent producers and other new players was another contributing factor to the upswing in activity. Shell Oil, for example, returned to the state in 2005; the company brought two drilling ships to drill four wells in the Beaufort Sea in 2007. Shell's plans were shelved due to permitting problems, but the company continues to work on the project. It has also launched plans for other offshore drilling programs.

In fact, Shell was the largest bidder in the 2008 Chukchi lease sale that netted \$2.7 billion, making it the highest lease bid in Alaska's history.

The surprise wasn't just the dollar amount; it was also its location. The leases are 50 miles offshore and hundreds of miles from any on-shore infrastructure. Such an investment could possibly be ushering in a new kind of oil development in Alaska.

Another example of a newcomer that's mixing things up in the industry is Pioneer Natural Resources. The company, with its minor partner, Eni Petroleum, made North Slope history when it finished the \$500 million-plus development of its offshore Ooguruk project in June. That made Pioneer the first independent to operate a producing oil field on the North Slope.

Other independents, newcomers and companies that have returned to the North Slope are either pursuing development in Alaska or have plans to do so. Those include FEX, Brooks Range Petroleum, Pacific Energy Resources, Statoil-Hydro and Petro Canada.

All that new activity is reflected in the oil industry's employment numbers. By 2006, oil industry employment reached near-record levels, and by 2007, the industry's employment zoomed past the 11,000 mark for the first time in history.

Another record was set last January when oil industry employment surpassed the 12,000 mark. It has remained at those new lofty levels through the first half of this year.

It's not unusual that most of that growth came from the oil field services side of employment and not the producers. (See Exhibit 6.) Typically, most of the changes in the level of oil industry employment come from the oil field service side of the industry. The producers, however, also grew – particularly BP.

BP's employment in 2000 was 1,018. By 2006 it reached 1,508 and it continued to grow. Some of BP's growth resulted from the company buying up Atlantic Richfield's assets. However, who would have thought that 20 years after oil production peaked in Alaska, the state's oil industry work force would reach new record-levels and oil would again become one of the fastest-grow-

ing industries in the state? (See Exhibits 3 and 7.)

Most of the work force is on the North Slope, in Anchorage and on the Kenai Peninsula

Nearly 90 percent of Alaska's oil industry employment is concentrated in three areas: Anchorage, and the North Slope and Kenai Peninsula boroughs. (See Exhibits 8 and 9.) The latter two are where all of the oil is produced; Anchorage is the state headquarters for many oil industry players.

Not surprisingly, the North Slope has the largest concentration of the oil industry's work force. Nearly half the North Slope's wage and salary employment stems from the oil industry.

Alaska's mature oil province, the Kenai Peninsula Borough, is home to oil and gas production, pipeline transportation, a liquid natural gas facility⁴ and an oil refinery. The borough also had a urea-ammonia fertilizer plant that used natural gas as its feedstock, but it closed in late 2007.

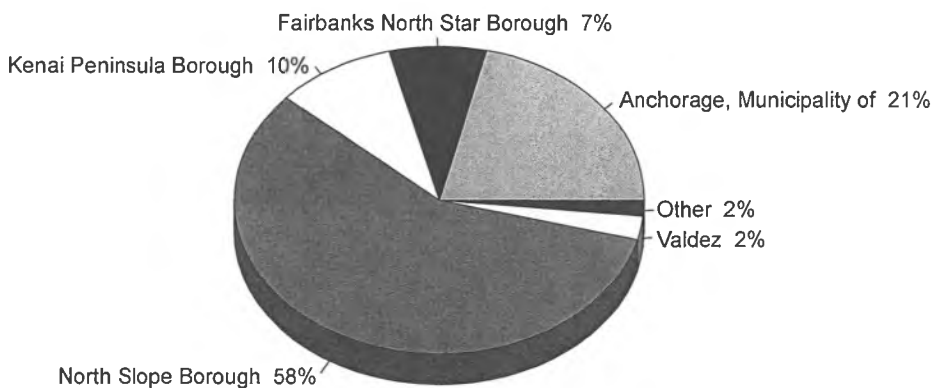
Combined, all those players represent 7 percent of the Kenai Peninsula Borough's wage and salary employment. Alone, the oil industry represents 5 percent. Because oil industry wages are more than twice the borough's average wage, the oil industry is responsible for 12 percent of the borough's wage and salary payroll.

In Valdez, most direct oil industry employment is tied to transporting oil from the North Slope through the trans-Alaska oil pipeline. Alyeska Pipeline Service Co. is the single-largest employer. SERVS⁵ is also a large employer. According to a recent Alaska Oil and Gas Association study, oil-related activity in 2007 generated nearly a

⁴Also called an LNG facility

⁵SERVS is an acronym for Ship Escort/Response Vessel Systems. SERVS is an Alyeska subsidiary but the employment for SERVS and Alyeska is counted separately.

Where the Oil and Oil-Related Jobs Are Alaska, 2007



Note: This exhibit includes oil and gas, refinery, urea and pipeline employment.
Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

quarter of Valdez's employment and more than a third of its payroll.

Although direct oil industry employment in the Fairbanks North Star Borough is relatively small, it's one of the North Slope's major logistic and supply centers. The same study attributes 3,250 jobs in Fairbanks to oil-related employment – 5.5 percent of the borough's wage and salary employment.

Fairbanks is also home to two oil refineries; Valdez has one.

A commuter work force

Although most jobs in the oil industry are concentrated in specific geographic areas, its work force is drawn from all around Alaska and the rest of the United States. That's particularly true for the North Slope, where only a few of the oil industry workers are North Slope residents.

After Anchorage residents, Matanuska-Susitna Borough residents and then Kenai Peninsula Borough residents form the second- and third-largest groups of Alaska residents who are North Slope workers, according to the 2000 Census. And there's little reason to believe that's changed since then. There's probably no area in the state that doesn't send some of its labor force to work somewhere in Alaska's oil fields.

9 Oil and Related Employment by Area Alaska, 2007

	Oil Industry Employment	Petrochemical and Refinery Employment ¹	Pipeline Transportation Employment	Total Oil and Oil-Related Industry Employment
Statewide	11,656	603	842	13,101
North Slope Borough	7,497	--	43	7,540
Anchorage, Municipality of	2,439	32	337	2,808
Kenai Peninsula Borough ¹	909	325	14	1,248
Fairbanks North Star Borough	656	180	144	980
Southeast Fairbanks Census Area	--	--	18	18
Valdez	31	32	253	316
Yukon-Koyukuk Census Area	--	--	33	33
Other	124	34	--	158

¹The Kenai Peninsula Borough portion of the petrochemical and refinery employment category consists of the borough's Agrium plant and Tesoro refinery employment.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

For example, in the Mat-Su Borough, where no oil industry exists, about 6 percent of the borough's working population commutes to the North Slope to work. That's not surprising because Mat-Su's average wage for all industries is a third lower than the state's average oil industry wage.

A different twist on that story is the fact that the Kenai Peninsula Borough, which has the second-highest concentration of oil industry jobs within its boundaries – the North Slope has the highest – also exports many of its residents to work in the oil industry elsewhere in the state.

Number of nonresidents in the industry grows

Over the past decade, between 25 percent and 31 percent of Alaska's oil industry workers have been nonresidents (see Exhibit 10), and wages paid to nonresidents in the industry have grown from \$243 million to \$328 million. The year 2006 was a record year for the number and percentage of nonresidents in the industry.

How does Alaska compare to other oil-producing states?

Since 1979, Alaska has been the nation's No. 2 oil-producing state. If federal offshore production is included, Alaska ranks third behind Louisiana. (See Exhibit 11.)

As far as the oil industry's importance to the economies of different states, there's little doubt Alaska ranks first. (See Exhibit 12.) However, a person wouldn't guess that by looking at the size of Alaska's oil industry work force.

Alaska produced 15 percent of the nation's domestic oil supply in 2007 but employed only 3 percent of the U.S. oil and gas work force. (See Exhibit 13.) Texas produced 75 percent more oil than Alaska the same year but its oil industry work force was

195,000 strong – 17 times as large as Alaska's. (See Exhibit 11.)

It's not just among the big producing states where that imbalance exists. In New Mexico, for instance, oil production in 2007 was less than a quarter as large as Alaska's but New Mexico's oil industry work force was more than 3,000 larger. Many of the states mentioned produce more gas than Alaska. (The gas work force is included in the employment numbers.) More on that later.

But that doesn't explain most of the difference. There are a host of reasons that explain Alaska's much-smaller oil industry work force, in light of its tremendous production.

One big reason is simply that Alaska's oil fields enjoy large economies of scale. Prudhoe Bay, which is still responsible for 36 percent of the state's oil production, is the largest oil field in the nation and doesn't need a huge work force to produce its oil. Other fields on the North Slope, such as Kuparuk – the nation's second-largest – and Alpine, Milne Point and Liberty, keep company with the nation's larger oil fields. In fact, 14 of the nation's 100 largest oil fields are in Alaska.

In Texas, Oklahoma, Wyoming and other oil-producing states, some oil is produced from very small fields. There are 400,000 marginal fields or stripper wells operating in the U.S. and

a stripper well produces 10 barrels of oil or less per day. In many of the states, there are literally thousands of families and small companies engaged in producing oil and gas – something nearly totally absent in Alaska.

The U.S. Census Bureau in 2006 identified 65 oil and gas establishments in Alaska, versus 754 in Wyoming, 1,305 in Oklahoma and 6,472 in Texas.

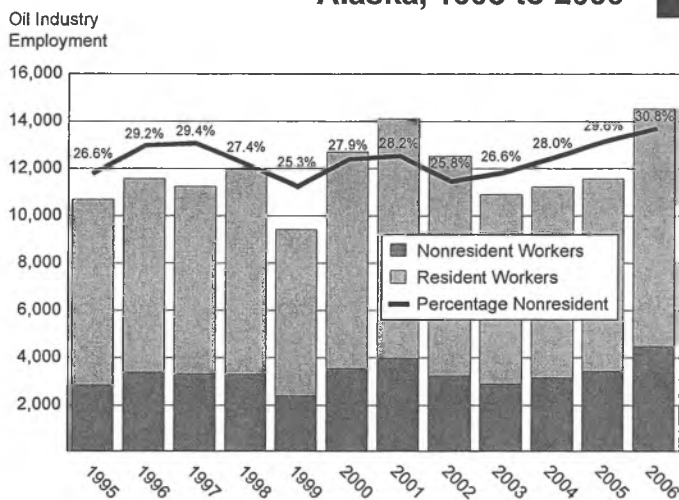
Another example of the difference between Alaska and other states is the number of wells being drilled. The Baker Hughes rig count for July was four for Alaska versus 923 in Texas. Even the count in Montana was higher than Alaska's. If Alaska's oil fields weren't as remote, employment in Alaska's oil patch would be considerably higher. Oil fields now considered marginal or simply noneconomic would be economic in a less remote environment.

Alaska is also less likely to be home to an oil industry headquarters or regional center, which also cuts into the size of its oil industry work force.

That's also true for many of the oil field service companies and contractors. Other functions, such as corporate, research and sometimes exploration, take place outside Alaska. For example, Houston alone is home to more than 85,000 oil and gas industry workers who are serving Texas' needs but also the rest of the nation's and the world's.

Yet, there are a group of firms in Alaska that are homegrown and have their headquarters in the state. They include companies such as ASRC Energy Services (the largest oil industry employer in

Share of Nonresidents Grows Alaska, 1995 to 2006 **10**



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Oil and Gas Industry Employment by State 11

Production and number of establishments, 2006 and 2007

	2007				2006		
	Oil and Gas Employment	Petroleum Refinery Employment	Pipeline Transportation	Oil Production (in thousands of barrels)	Gas Production (in millions of cubic feet)	Number of Oil and Gas Establishments	
Alaska	11,656	400	842	270,481	444,724	65	
Texas ¹	195,031	21,151	13,428	475,069	5,513,739	6,472	
California	18,346	12,893	2,750	249,698	315,209	525	
Colorado	18,913	--	--	23,903	1,202,821	907	
Louisiana ¹	46,610	--	2,441	468,383	1,361,119	1,438	
Oklahoma	43,236	--	--	63,447	1,688,985	1,305	
New Mexico	15,070	--	--	59,876	1,609,223	609	
Wyoming	17,730	--	--	53,039	1,816,201	754	
U.S. Total	437,600	--	--	1,862,908	19,381,895	18,118	

¹These categories include federal offshore Gulf of Mexico oil production. They don't include offshore natural gas production.

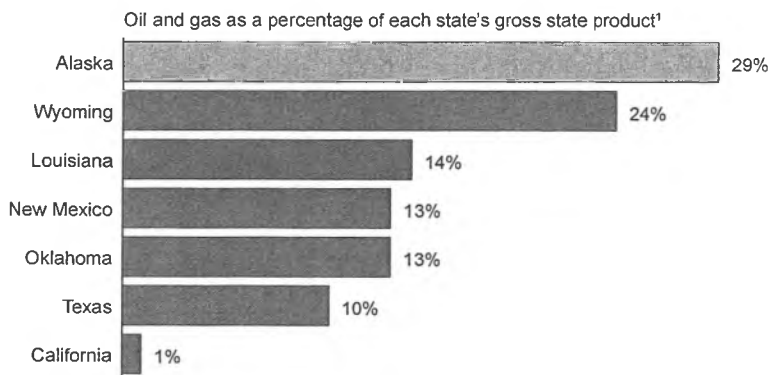
Sources: Alaska Department of Labor and Workforce Development, Research and Analysis Section; the labor departments for Texas, California, Colorado, Louisiana, Oklahoma, New Mexico and Wyoming; U.S. Department of Energy, Energy Information Administration; and U.S. Census Bureau

the state), AES-Houston Contracting Company, Peak Oilfield Service Company, Udelhoven Oilfield System Services, Doyon Drilling and others. Just recently, Arctic Slope Regional Corporation announced it would no longer just be an oil service contractor – it would get involved in exploration and oil production as well.

But what is also true is that nearly all Alaska's oil industry work force is in the state solely to produce oil and gas in Alaska, not to provide

12 An Outsized Effect on Alaska

Alaska and other states, 2006



¹The percentages in this exhibit are estimates only. Due to the unavailability of Bureau of Economic Analysis detail, an assumption of support mining activities was made. The oil and gas contribution for the states, with the exception of Alaska, may be slightly too high.
Source: U.S. Department of Commerce, Bureau of Economic Analysis

their services elsewhere in the country or world. There are of course exceptions. Some Alaska-based firms have taken their arctic and other types of expertise and performed work Outside, but they're the exception.

Not only does Alaska have a considerably smaller oil extraction work force, it also has a smaller transportation infrastructure and fewer downstream operations, such as refineries. (Texas' refinery capacity is 4.6 million barrels per day compared to Alaska's 375,000.) And while Alaska has an 800-mile pipeline and a number of smaller ones, its pipelines don't compare to the thousands of miles of pipelines that snake through other states.

Alaska refineries for the most part only service local demand, which is relatively small. One exception is the jet fuel the state's refineries process for the huge international cargo fleet operating out of Anchorage. Alaska's refineries include Flint Hills and Petro Star in Fairbanks, Tesoro in Kenai, Petro Star in Valdez and two very small refineries on the North Slope.

Until recently, Alaska had only two downstream operations other than refineries, and that number was whittled down to one when Agrium's Kenai Peninsula fertilizer plant closed last year, as mentioned earlier. The only player now is ConocoPhillips' liquid natural gas facility on the Kenai Peninsula, which exports its product to Japan.

Among America's energy producers, Alaska is among the slow-growers

Alaska obviously isn't the only state or country enjoying the resurgence in oil industry activity – oil at \$100-plus a barrel does wonders for the industry. Although a record number of oil and gas industry workers are currently working in Alaska's oil fields and the oil industry is now one of the most dynamic in the state, Alaska is growing more slowly compared to most other oil and gas producing states.

Oil industry employment in the rest of the U.S. began to grow in 2004, two years before it started to grow in Alaska. Between 2000 and 2007, employment in the U.S. grew by 44 percent versus 34 percent for Alaska. In contrast, employment in Wyoming more than doubled (113 percent) and in Texas it grew by 49 percent over the same period.

There are probably a number of reasons for Alaska's less-robust growth. One certainly is its remoteness and associated costs. However, there are other reasons. In all other energy-producing states, there are far more players in the industry and they come in all different sizes, which probably makes them more nimble – whereas Alaska is dominated by a handful of large companies that tend to move more slowly in a changing environment.

Another big reason for the difference is the role natural gas is playing in the upswing in employment activity. Unfortunately, there's no current method to separate oil from gas-related employment.

While oil production in many states and the nation as a whole has been in decline since the mid-1970s, that hasn't been the case for natural gas production. In fact, nationally, natural gas production in 2007 reached its second-highest level in 27 years. Probably the only reason it was higher in the early 1980s was because gas production was often a byproduct of oil exploration.

A Small Share of the Nation's Jobs Oil and gas employment, 2007

13

A natural gas boom is taking place in many parts of the country, particularly in the Rocky Mountain states, and New Mexico, Oklahoma and Texas. Natural gas production in the past decade has doubled in Colorado and Montana, and has more than doubled in Wyoming, now one of the nation's largest natural gas producers.

Most current growth in Wyoming's oil and gas work force is tied to the production of gas, although oil production has also edged up in the past two years.

Nearly all Alaska's natural gas production has been in Cook Inlet. It peaked in 1996 and has gradually declined.

High earnings are its big attraction

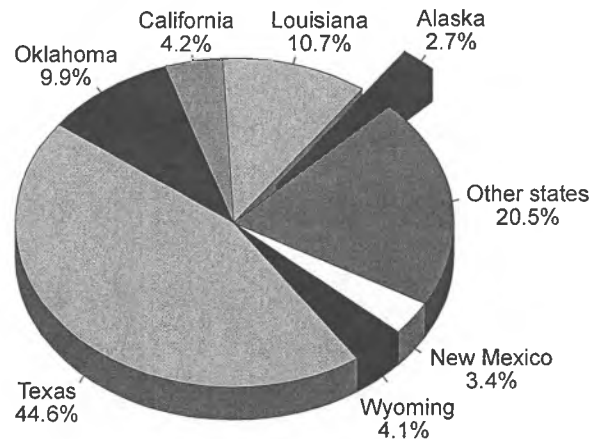
It's a well-known fact that wages in Alaska's oil industry are an outlier on the high side. The average annual wage for an oil industry job in 2007 was \$108,538. (See Exhibit 14.) That's nearly two and a half times more than the state-wide average of \$43,524.

There are several reasons for the difference in pay, but what factors weigh heavier and which are less important isn't clear. Certainly, the profitability of the industry plays a role. The level of the required skills and experience, along with the demanding work schedules, are also factors.

Overtime, mostly stemming from shift schedules on the North Slope or on Cook Inlet platforms, plays a big role too. The most common shifts are week on/week off or two weeks on/two weeks off. Remote-based employees often work 84 hours a week, which means 40 hours of straight time and 44 hours of overtime.

Other reasons for the higher pay include the remote work site settings, the hazards of some occupations, and the extreme climate workers encounter on Alaska's oil fields. Workers' prolonged periods of separation from their families are definitely a factor in the equation. Longer tenure in the industry is also reflected in hourly pay rates.

The U.S. Oil and Gas Industry



Sources: U.S. Department of Labor, Bureau of Labor Statistics; the labor market information Web sites for California, Louisiana, New Mexico, Oklahoma, Texas and Wyoming; and Alaska Department of Labor and Workforce Development, Research and Analysis Section

Wages in oil producer companies tend to be higher than those in oil field or drilling support firms – the average annual wage for the producers was \$152,840. And more job security usually exists with the producers. Work in oil field or drilling support companies often tends to be more project-orientated, which explains to some degree their more volatile employment levels. Annual wages among the non-oil industry employers in the oil patch are considerably below the annual wages for both the oil producer companies and the oil field or drilling support companies.

Big stuff must happen to keep these numbers positive

Employment in the oil industry has waxed and waned over time, but after oil production peaked, it was logical to believe that the labor force in the industry would generally follow oil production's declining trend. There were periods with flurries of activity to help stem the production decline, and employment would rally for a while, but further declines followed.

Yet in 2007, record oil prices, an oil spill and other activity pushed employment to record

14 Oil Industry's Wages Are Highest in Alaska, 2007



Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

highs, all while oil production continued to decline. However, it's probably clear that without other major developments or discoveries, the higher employment numbers will be temporary and those numbers will resume the broader downward trend.

There are ventures on the horizon, though, that might stem future losses and propel the

oil industry to new heights, launching the state into a new oil and gas epoch. It all started with Cook Inlet, then moved on to Prudhoe Bay. Alaska could now be on the threshold of a new era by becoming one of the nation's largest gas producers.

Two economic indicators, two different story lines

Alaska's seasonally adjusted unemployment rate rose two-tenths of a percentage point in July to 6.9 percent. June's preliminary rate was revised down one-tenth of a percentage point to 6.7 percent.

After steadily rising for most of 2007 and the first part of 2008, the state's rate has bounced around over the last four months and has not revealed a clear trend. For its part, the U.S. rate continued its gradual climb, rising two-tenths of a percentage point in July to 5.7 percent, a full percentage point higher than in July 2007.

Similar trends for Alaska and U.S. unemployment rates

The Alaska and U.S. rates have followed the same broad trends since at least 2001. (See Exhibit 1.) The national recession in the early part of the 2000s drove the U.S. rate from a low point of 4.2 percent to a high of 6.3 percent. After a lag of several months, Alaska's rate followed a similar course, rising from 6 percent to almost 8 percent between 2001 and 2003.

After the recession ended, the U.S. rate steadily fell until it reached a low point of 4.4 percent

in early 2007. Alaska's rate fell by roughly the same margin and bottomed out at 6 percent in early 2007. Since then, both the U.S. and Alaska rates have climbed as the nation has likely entered another recessionary period.

Looking just at unemployment rates, it may be tempting to conclude that Alaska's economy follows the same business cycles as the nation, and that both economies are currently in the midst of a slowdown. The rates seem to suggest that when the nation's economy is thriving Alaska's is doing likewise and that recessions afflict both economies during roughly the same time periods.

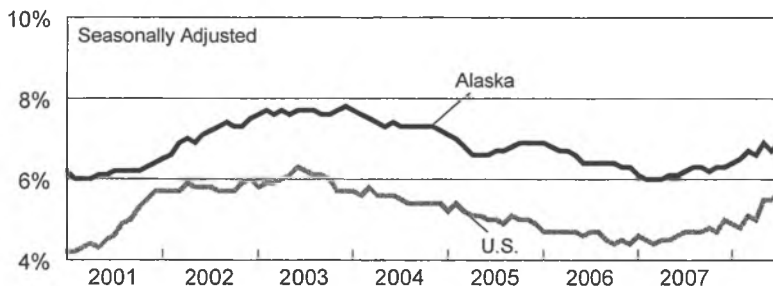
Job growth tells a different story

But unemployment rates can be a complicated economic indicator, and although they provide important information about the percentage of the labor force looking for work, they shouldn't be seen as a simple barometer of an economy's health – especially at the state level.

A more simple and straightforward tool for assessing the health of an economy is the rate of growth in payroll jobs. Unlike unemployment rates, which over the short term can rise as an economy strengthens and fall as an economy weakens, an increase in payroll jobs almost always equates to economic growth and a decline in the payroll job count almost always means economic distress.

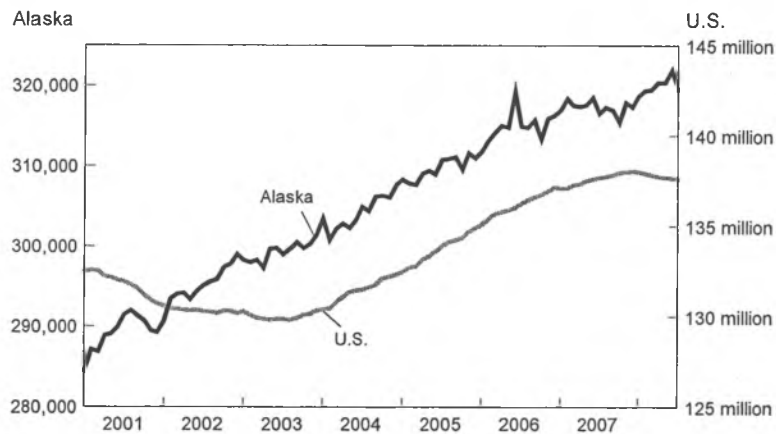
At the national level, the pattern of payroll job growth and loss is generally a reverse image of the rising and falling of the unemployment rate. For example, the U.S. economy registered job losses during the 2001-2002 recession as the unemployment rate climbed, and is showing losses again in 2008 as the unemployment rate has pushed upward. (See Exhibits 1 and 2.)

1 Unemployment Rates, Alaska and U.S. January 2001 to July 2008



Sources: Alaska Department of Labor and Workforce Development, Research and Analysis Section; U.S. Department of Labor, Bureau of Labor Statistics

2 Payroll Employment, Alaska and U.S. January 2001 to July 2008



Sources: Alaska Department of Labor and Workforce Development, Research and Analysis Section; and U.S. Department of Labor, Bureau of Labor Statistics

But Alaska's payroll numbers over those same years bear little resemblance to the state's pattern of rising and falling unemployment rates. Unlike the up-and-down U.S. payroll numbers, Alaska's data show consistent, moderate growth in payroll employment¹ with little apparent relationship to trends in the unemployment rate. (See Exhibits 1 and 2.)

Reconciling the two indicators

All this begs the question of how unemployment rates can rise in Alaska without payroll jobs falling as they nearly always do for the nation. The most likely explanation is that Alaska's unemployment rates over the 2001 to 2008 period have been driven more by a slosh of workers back and forth to the state from neighboring states than by changes in Alaska's ability to sustain and increase its count of payroll jobs.

As separate and distinct from the rest of the U.S. as Alaska can seem, it's important to remember

¹The jagged line of the graphed Alaska data also show the difficulty of seasonally adjusting numbers in a state where seasonal patterns are dramatic and occasionally shift due to the timing of fish harvesting and, less frequently, changes in weather patterns. The much smoother seasonally adjusted data for the U.S. reveal a more predictable seasonality, both in terms of the timing of seasonal movements and the magnitude of the movements. Because of Alaska's unruly seasonal patterns, the seasonally adjusted data aren't as reliable in interpreting changes from one month to the next as they are for the U.S. The seasonally adjusted data for Alaska are still useful, though, because over a period of several months they reveal changes in underlying trends more effectively than unadjusted data can.

that workers from other states can freely move to Alaska in search of employment and that Alaskans can freely move to other states when opportunities beckon.

The flow of workers to and from the U.S. is a much more regulated affair, with immigration laws and regulations limiting movement. With a more static labor pool, the nation generally sees corresponding changes in unemployment rates and payroll employment: when unemployment rates show a sustained upward trend, payroll jobs are usually falling and vice versa.

As a state with a highly seasonal, resource-based economy – and a climate that's not for everyone – Alaska has a particularly fluid resident population. About 6 percent of residents are new to the state each year and roughly that percentage also leave.

The number of people who migrate to Alaska – whether seasonally or with the intention of staying longer and making Alaska their home – is affected by the relative health of their home economies. If good jobs are plentiful locally, a person is less likely to look to Alaska for employment.

The same is true of Alaskans weighing the pros and cons of leaving the state for employment-related reasons. If the U.S. is in the midst of a recession, an Alaskan in search of work is less likely to leave the state than when the U.S. economy is strong and jobs are easier to come by.

Consequently, the number of unemployed workers and the unemployment rate in Alaska appear to have risen and fallen more in response to the rising and falling of the U.S. economy than to changes in the state's ability to generate job growth, which has been remarkably consistent for more than two decades.

It's important to recognize, though, that there are other possible explanations for why Alaska's unemployment rate could have been up and down during periods of relatively consistent payroll job growth. As noted, the rate is a compli-

cated indicator. Even assuming no migration to and from Alaska, the unemployment rate would change as the state's existing population moved in and out of the labor force.²

Job growth states benefiting from oil and gas boom

Through the first seven months of 2008, 28 of the 50 states registered a decline in payroll jobs and the nation as a whole lost more than 450,000 jobs.

On a percentage basis, the state with the biggest loss was Rhode Island with a 2.1 percent drop, followed by Florida, Arizona, Nevada and Indiana. (See Exhibit 3.)

Bucking the national trend are Texas and several other states that are benefiting from strong growth in the oil and gas industry. Alaska is tied with Montana and Wyoming for the fourth-highest growth rate in the country so far in 2008.

Nationwide, the natural resources and mining sector, which includes the oil and gas industry in addition to coal mines and other mining employers, has added about 40,000 jobs so far in 2008.

Payroll data follow seasonal trends

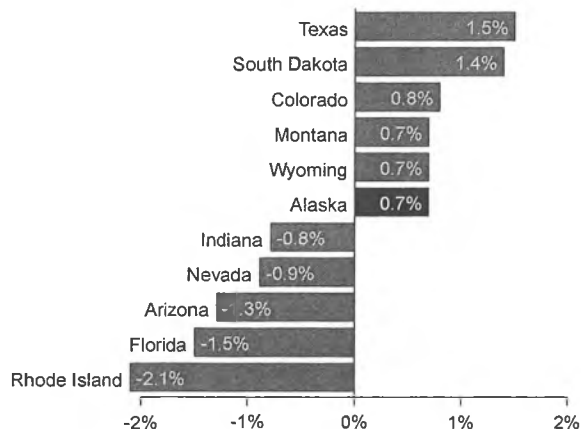
July and August are Alaska's peak employment months and the unadjusted payroll numbers show the expected seasonal increase. The net gain from June to July was 3,600 jobs as most of the state's seasonal employers shifted into their highest gears.

Seafood processing employment jumped by an estimated 5,800 in July and the construction and accommodations industries both added 600 jobs. Those additions more than compensated

²To be counted as unemployed, a person must be actively seeking work. So when a retired person decides to go back to work and starts looking for a job or a student who has recently graduated begins a job search, the number of unemployed people rises even though the population hasn't changed. The labor force, which is the universe from which the unemployment rate is calculated, consists of two parts: 1) those people who aren't working but actively seeking work, and 2) those people who are working (there are some exceptions where people are counted as employed even though they aren't working – people on paid leave, for example).

Alaska Doing Better than Most States Payroll job growth in 2008,¹ highs and lows

3



¹ December 2007 to July 2008

Source: U.S. Department of Labor, Bureau of Labor Statistics

for the large seasonal decline in local government (-5,200) as public schools let out for the summer.

Job growth mostly in Anchorage/Mat-Su and Northern regions

Nearly all the state's over-the-year job growth was in the Anchorage/Mat-Su and Northern regions. (See Exhibit 6.) Growth in the Northern region is obviously driven by oil and gas, but so is much of the Anchorage/Mat-Su growth.

The oil companies' job counts in Anchorage have grown by an estimated 300 over the year and high levels of activity for the industry have stimulated growth in a variety of other industries. The Mat-Su Borough's growth continues to come predominately from its connection to Anchorage's job market.

A dramatic range of unemployment rates in July

July unemployment rates throughout the state ranged from a high of 26.8 percent in the Wade Hampton Census Area to a low of 1.5 percent in the Bristol Bay Borough. (See Exhibit 5.) Local unemployment rates were generally higher over the year, following the statewide trend. The only exception big enough to be of consequence was the North Slope Borough, which had a 4.7 percent rate in July compared to 6.0 percent in July 2007.

4 Nonfarm Wage and Salary Employment

	Preliminary	Revised	Revised	Changes from:	
	7/08	6/08	7/07	6/08	7/07
Alaska					
Total Nonfarm Wage and Salary ¹	342,300	338,700	339,400	3,600	2,900
Goods-Producing ²	57,200	50,600	57,000	6,600	200
Service-Providing ³	285,100	288,100	282,400	-3,000	2,700
Natural Resources and Mining	15,200	15,100	14,100	100	1,100
Logging	300	300	400	0	-100
Mining	14,900	14,800	13,700	100	1,200
Oil and Gas	12,800	12,600	11,500	200	1,300
Construction	20,500	19,900	20,700	600	-200
Manufacturing	21,500	15,600	22,200	5,900	-700
Wood Product Manufacturing	400	400	400	0	0
Seafood Processing	17,200	11,400	17,900	5,800	-700
Trade, Transportation, Utilities	69,900	68,800	69,100	1,100	800
Wholesale Trade	7,000	6,900	6,900	100	100
Retail Trade	38,700	38,200	38,100	500	600
Food and Beverage Stores	6,800	6,700	6,900	100	-100
General Merchandise Stores	9,500	9,400	9,500	100	0
Transportation, Warehousing, Utilities	24,200	23,700	24,100	500	100
Air Transportation	6,900	6,800	6,800	100	100
Truck Transportation	3,500	3,400	3,500	100	0
Information	7,000	6,900	7,000	100	0
Telecommunications	4,300	4,300	4,300	0	0
Financial Activities	15,500	15,400	15,500	100	0
Professional and Business Services	27,100	27,100	26,400	0	700
Educational⁴ and Health Services	37,000	37,300	36,700	-300	300
Health Care	27,000	27,100	26,800	-100	200
Leisure and Hospitality	39,300	38,700	39,600	600	-300
Accommodations	11,900	11,300	12,000	600	-100
Food Services and Drinking Places	22,100	22,100	22,100	0	0
Other Services	11,700	11,700	11,700	0	0
Government	77,600	82,200	76,400	-4,600	1,200
Federal Government ⁵	17,700	17,400	17,600	300	100
State Government	24,400	24,100	24,000	300	400
State Government Education ⁶	5,700	5,800	5,600	-100	100
Local Government	35,500	40,700	34,800	-5,200	700
Local Government Education ⁷	16,800	21,900	16,400	-5,100	400
Tribal Government	3,800	3,700	3,800	100	0

Notes for all exhibits on this page:

¹ Excludes the self-employed, fishermen and other agricultural workers, and private household workers; for estimates of fish harvesting employment, and other fisheries data, go to labor.alaska.gov/research/seafood/seafood.htm

² Goods-producing sectors include natural resources and mining, construction and manufacturing.

³ Service-providing sectors include all others not listed as goods-producing sectors.

⁴ Private education only

⁵ Excludes uniformed military

⁶ Includes the University of Alaska

⁷ Includes public school systems

⁸ Fairbanks North Star Borough

Sources for Exhibits 4 and 5: Alaska Department of Labor and Workforce Development, Research and Analysis Section; and the U.S. Department of Labor, Bureau of Labor Statistics
Sources for Exhibit 6: Alaska Department of Labor and Workforce Development, Research and Analysis Section; also the U.S. Department of Labor, Bureau of Labor Statistics, for Anchorage/Mat-Su and Fairbanks

6 Nonfarm Wage and Salary Employment By region

	Preliminary	Revised	Revised	Changes from:		Percent Change:	
	7/08	6/08	7/07	6/08	7/07	6/08	7/07
Anch/Mat-Su	173,300	175,500	171,600	-2,200	1,700	-1.3%	1.0%
Anchorage	153,300	155,300	152,500	-2,000	800	-1.3%	0.5%
Gulf Coast	33,600	33,000	33,500	600	100	1.8%	0.3%
Interior	49,000	49,000	49,400	0	-400	0.0%	-0.8%
Fairbanks ⁸	39,900	39,900	39,900	0	0	0.0%	0.0%
Northern	19,700	19,600	18,600	100	1,100	0.5%	5.9%
Southeast	42,500	40,450	42,700	2,050	-200	5.1%	-0.5%
Southwest	23,850	21,250	24,000	2,600	-150	12.2%	-0.6%

5 Unemployment Rates By borough and census area

	Prelim.	Revised	Revised
	7/08	6/08	7/07
SEASONALLY ADJUSTED			
United States	5.7	5.5	4.7
Alaska Statewide	6.9	6.7	6.2
NOT SEASONALLY ADJUSTED			
United States	6.0	5.7	4.9
Alaska Statewide	6.1	6.8	5.6
Anchorage/Mat-Su Region	5.7	6.2	5.2
Municipality of Anchorage	5.3	5.8	4.9
Mat-Su Borough	7.3	7.9	6.7
Gulf Coast Region	6.4	7.5	5.8
Kenai Peninsula Borough	6.7	7.3	6.0
Kodiak Island Borough	5.4	9.3	5.5
Valdez-Cordova Census Area	6.0	6.6	5.4
Interior Region	5.9	6.5	5.2
Denali Borough	2.2	2.5	2.1
Fairbanks North Star Borough	5.5	6.1	4.8
Southeast Fairbanks Census Area	7.6	8.4	7.0
Yukon-Koyukuk Census Area	15.0	14.9	12.8
Northern Region	9.3	9.8	9.5
Nome Census Area	13.2	13.3	12.8
North Slope Borough	4.7	5.2	6.0
Northwest Arctic Borough	12.1	12.9	11.0
Southeast Region	5.2	6.1	4.6
Haines Borough	4.2	7.6	3.1
Juneau Borough	4.3	4.9	3.9
Ketchikan Gateway Borough	4.5	5.5	3.9
Prince of Wales-Outer Ketchikan CA	12.6	12.0	11.1
Sitka Borough	5.1	5.7	4.6
Skagway-Hoonah-Angoon CA	5.9	7.0	5.8
Wrangell-Petersburg Census Area	7.6	10.1	6.1
Yakutat Borough	5.6	6.3	4.1
Southwest Region	10.7	12.4	9.5
Aleutians East Borough	6.4	9.2	5.3
Aleutians West Census Area	4.7	6.8	3.8
Bethel Census Area	15.1	15.5	13.3
Bristol Bay Borough	1.5	2.7	1.5
Dillingham Census Area	8.0	10.6	7.2
Lake and Peninsula Borough	5.1	5.5	3.6
Wade Hampton Census Area	26.8	23.4	25.2

For more current state and regional employment and unemployment data, visit our Web site. We have a new address:

laborstats.alaska.gov

A Safety Minute

A Focus on Crane Safety

Serious crane accidents across the country are making news this construction season. One occurred in July when a crane tipped over and crushed a bystander during a steeple-mounting ceremony in Oklahoma. In the past several months, accidents in Nevada, New York, Florida and Texas have claimed the lives of workers and bystanders.

"These crane accidents illustrate the importance of crane and jobsite safety," said Labor Commissioner Click Bishop. "In Alaska we haven't had a crane-related fatality for several years and I intend to keep it that way with a proactive safety effort. We ask all employers who use cranes to review crane lifting and safety policies, check cranes for mechanical integrity, and ensure crane operators are qualified and use appropriate safety procedures."

While there's no state requirement for crane operator certification, Alaska's Occupational Safety and Health regulations require employers who use cranes to ensure every operator has appropriate training, knowledge and experience, and is physically fit to operate a crane. It's the employer's responsibility to adequately inspect and maintain the crane and rigging.

It's also critical for employers to ensure that employees assisting with the lift are properly trained – including signaling, load limits and rigging techniques – and are aware of the hazards of operating a crane.

"I ask that all employers, safety professionals, crane operators and other concerned Alaskans stand by me and make sure that 'we all go home safely tonight,'" Bishop said.

For help with crane standards in Alaska, employers should contact the Alaska Department of Labor and Workforce Development's Alaska Occupational Safety and Health Consultation and Training Section at (800) 656-4972. The section is within the department's Labor Standards and Safety Division.

Employer Resources

Workers' Compensation Requirements

The Alaska Workers' Compensation Act requires all employers with one or more employees in Alaska to have workers' compensation insurance, unless the employer has at least 100 employees and has been approved as a self-insurer.

Employers purchase workers' compensation insurance from commercial insurance carriers. Once employers have insurance, they're required to post in their workplaces an Employer's Notice of Insurance, which insurance companies provide. Employers must also submit proof of insurance to the Workers' Compensation Division, the administrative arm of the Workers' Compensation Board.

Executive officers of for-profit corporations are required to have workers' compensation insurance unless they choose to waive coverage by filing a waiver with the division.

If employers are unable to obtain insurance coverage from a commercial carrier, they can purchase insurance through a state-assigned risk pool. And if employers feel their insurance premium is incorrectly calculated, they can request arbitration.

For more information or forms, call the Workers' Compensation Division at (907) 465-2790 or visit the division's Web site. Go to the Alaska Department of Labor and Workforce Development Web site at labor.alaska.gov. Under "Division Links" on the left, click on "Workers' Compensation." Then under "Quick Links" on the right, click on "Employer Information." For the Employer's Notice of Insurance form, under "Quick Links," click on "Forms."