

Jim Sykes Testimony to the House Resources Committee on SB21 April 2, 2013

Introduction

I made some brief comments to the House Resources Committee earlier today and they are included below, reconstructed from my notes and included with more detailed remarks with charts and other appendices. I tried to speak about what I thought the current CS might or might not do.

Maybe it's worth a moment of reflection about what is being attempted—to reach a long term solution on oil taxes. For now, Alaska's short term needs have some cash reserve cushion, which is liable to get thinner mainly by the rising cost of government.

What is the target to work from?

What is the date at which we expect Alaskans to pay taxes and/or start spending down the Permanent Fund to pay for state government?

We can start with the current amount of money being spent and input the sources of revenue, including oil. The natural decline curve of currently producing fields is fairly predictable. How much money can we extract from the economic rent for our oil and gas, including royalties, lease payments and all taxes? If we are able to stimulate more production now, will the finite pool of oil suffer a steeper decline later? What will be the long term effect of a steeper decline?

While I've followed the various proposals and debates, I'm troubled that these kinds of questions aren't being asked. When asked recently about whether the industry would reinvest a tax credit in Alaska, a company representative described the process.

Basically all tax credits are welcome. The company will gladly take any credits and add them to corporate cash. However projects will be developed that are prioritized from among a pool of the most promising. That means there is no assurance that even a large tax credit, aimed at raising production in an older oil field, will raise Alaska above other newer projects elsewhere.

While there will undoubtedly be more oil extracted from Alaska than has already been taken out, it will occur over the next 50-60 years, or longer. [Please see Appendix A].

Alaska is a “big basin” oil patch, developed differently than the small rigs that drill shallow plays in Texas and North Dakota. Why wouldn't an oil producer be interested in a place where you can drive in a truck, set up a small rig extract some oil and move on? This latest boom, based on new technology, was not based on a tax policy change. The government take in North Dakota is smaller, in part because companies pay royalties on the order of 20% to 40% to the private land owners. Alaska's royalty rate is 12.5% on most state lands. If our royalty rate were 35% a lower tax rate would be reasonable.

It is unlikely Alaska can lower its taxes enough to take away another oil region's production boom. No one was able to take away Alaska's boom in the late 1970's and early 1980's. So whatever tax break is considered needs to have a purpose and a predictable outcome. Declines reversed by the use of tax cuts have mainly, perhaps only, happened with a change in oil field operators.

Prudhoe and Kupark are so immensely profitable, the current incumbents are not likely to leave. The state needs to understand that profitability. In my testimony I used the term “like an ATM” to even out highs and lows for corporate activities elsewhere in the world. [Please see Appendix D].

How much is the state prepared to lose from its own cash reserves to get a rise in production? How much production will be required to cover the loss, and when will the state see a profit from the incentives that are given? If ever? If production is actually increased soon will it steepen decline in out years? Are we trying to get extra income now, when cash flows are good, to the detriment of future cash flows?

Alaska's Permanent Fund is a magnet for economic activity. If the flow to the fund is reduced is reduced or cut off there could be a large negative impact on economic activity in Alaska. Because of the Permanent Fund, Alaska to has the narrowest gap between low and high income earners, and that too could decrease and eventually end.

So both the long term and short term questions remain. How does government continue when revenue receipts decrease to the point that government funding is not sustainable? Is the current tax break attempting to push production up for a short time at the expense of future receipts?

We deserve solid answers to these types of questions while the state is in a relative good cash position.

Increased production does not guarantee more revenue to the state.

The hope that more money results from increased production may only be true in a high oil price scenario. If world oil prices go down, as many are predicting, the state can lose in two ways, 1) Starting to credit low oil price losses at the high oil price of \$90, and 2) continuing to give tax credits which may or may not cover losses of credits given or provide adequate profits to the state.

The way the current CS for SB21 starts support for low oil prices below \$90 per barrel, and then severely restricting progressivity on the upside, effectively means the state can counts on stable revenue between \$90 and \$120 oil. While we've been in that range for a while there are no assurances such prices will continue.

For those of us who have been observing the ups and downs of oil markets, they've always gone up and they've always come down, and there's no reason to believe it won't happen again. It's up to the legislature to figure out how the state will minimize the risks and maximize its opportunities for the benefit of Alaskans that our constitution requires.

A word about throughput.

In 1988, TAPS oil flowed 2 million bpd at its peak, and that year the state brought in \$2.68 billion, roughly \$5.21 billion in 2012 dollars. In 2012, the state took in \$8.86 billion on 515,000 bpd. In today's dollars, Alaska is making more than six times more per barrel than in 1988. Price is more important than the amount of oil being produced.

There are a couple large variables, somewhat beyond our control, of how much TAPS will handle. Offshore oil, predicted to increase greatly in about 10 years may reach a peak of 1.7 mmbd, which is close to the 2 mmbd of 1988. [Please see Appendix A].

On the low end, suggestions that the pipeline will shut down at 300,000 or 250,000 bpd are not true. The large amount of booked reserves and test projects envision TAPS being able to handle as low of volume as 70,000 bpd, with some modifications. [Please read TAPS Settlement Excerpts in Appendix B]. TAPS was sized to accommodate the anticipated peak of Prudhoe and it will be able to accommodate heavy oil and offshore oil as well.

The practical matter for the legislature to consider is that making a lowball tax deal now, during this 10 year lull between huge developments, could deprive Alaskans and the state government the maximum benefits that our constitution says we must obtain.

We also need to know what the payback period is on new wells from existing pads in Prudhoe and Kuparuk under the current tax law and the CS for SB21 proposal. As I mentioned, companies might be willing to share confidential information, but someone has to have the guts to ask, and also be prepared to sign a confidentiality agreement.

The legislature may have been working on the oil tax issue for the past three years, and it may be frustrating. There's a great deal of knowledge and evidence that needs to be considered. Getting it right is essential.

Source material for Jim Sykes' verbal testimony, April 2, 2013

Co-Chairs and Members of the House Resources Committee,

My name is Jim Sykes, I've followed the oil industry and state oil policy for quite a long time. As one who would also like to see an increase in oil production, I speak against the new CS for SB21.

For companies there are many upsides without downsides. For the state, few potential upsides and huge potential downsides. It looks to me that the current SB21 CS essentially guarantees more corporate profits on top of already record profits without assurances that new investment will happen, or that production will increase or that the state will recoup the loss of the credits given in advance.

Other upsides for companies include:

- Starting to eliminating the downside price risk at about \$90, which does not pass the red face test,
- Eliminates the upside price risk by severely restricting progressivity,
- Allows us use of the state's money without requiring actual performance of new production
- The tax credit for new production looks like it applies to the legacy fields, which are already among the most profitable oil fields on the entire planet. In fact our legacy fields are the ATM that levels out the ups and downs of other investments made by Alaska producers elsewhere in the world. [Please see Appendix D].

The State of Alaska:

- Gives up its cash in advance, risking fairly quick negative cash flows regardless of oil price,
- Hopes, but has no assurance, that oil production will actually increase,
- May not be able to recoup the value of the credits even if production is increased,
- Risks paying for credits if oil prices decline and keeps itself from substantially higher profits if prices substantially rise.

It is certain that larger net profits will accrue to oil companies corporations and the state will essentially be accepting a effective lower net take per barrel.

We face another critical juncture in Alaska's history whether the people of Alaska will control our resources or outside corporations that hold our oil leases. We find ourselves in a similar predicament that Bob Bartlett warned the Alaska Constitutional Convention about in 1955:

“...This moment will be a critical one in Alaska’s future history. Development must not be confused with exploitation at this time. The financial welfare of the future state and the well being of its present and unborn citizens depend upon the wise administration and oversight of these developmental activities.

Two very real dangers are present. The first, and most obvious, danger is that of exploitation under the thin disguise of development. The taking of Alaska’s mineral resources without leaving some reasonable return for the support of Alaska governmental services and the use of all the people of Alaska will mean a betrayal in the administration of the people’s wealth.

The second danger is that outside interests, determined to stifle any development in Alaska which might compete with their activities elsewhere, will attempt to acquire great areas of Alaska’s public lands in order NOT to develop them until such time as, in their omnipotence and the pursuance of their own interests, they see fit. If large areas of Alaska’s patrimony are turned over to such corporations the people of Alaska may be even more the losers than if the lands had been exploited....”

Both upsides and downsides of SB21 need to be carefully considered and many questions need answers.

Should the state end up with less than it's fair share, or things don't work out as hoped, a large portion of corporate tax burden will be shifted onto the shoulders of Alaska's people. Undoubtedly, people will still want schools, roads, bridges, maybe a hydroelectric dam and public safety, but they will either have to tax themselves, start depleting their Permanent Fund or both.

Before tax credits have the potential to raise production in the short term, funding shortfalls for state government are shortly before us. If new production is realized, how much lost revenue will be replaced? If credits revenue is not replaced, the funding of government services risk decline along with the revenue decline. The state could lose both existing and future cash potential.

Meantime, oil corporation boards will be happy. Shareholders will be glad to see record corporate profits increase. A corresponding decrease will come from state coffers.

If a major change in accounting is to take place, separate accounting could be initiated. All credits and taxes could apply only to Alaska production. The separate accounting mechanism has already been tested and approved in court. Even before that an audit on the current tax system needs to be performed as the only fiscally prudent way to evaluate how any new tax scheme compares with the present one.

SB21 is clearly in the companies interest, but for the State the outcome is uncertain. Please proceed carefully with full consideration for Alaska's future. It is greatly appreciated.

Thank you for the opportunity to testify. I'm glad to answer any of your questions.

A handwritten signature in black ink that reads "Jim Sykes". The signature is fluid and cursive, with the first name "Jim" and last name "Sykes" clearly distinguishable.

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Attachments: Appendix A-Charts, Offshore oil, Undiscovered oil, Reserves
Appendix B-Excerpts from Gleason, TAPS Settlement
Appendix C-News Story on TAPS life settlement proposal
Appendix D-PrudhoeATM Chart

Oil Cos. Reach Deal On Trans-Alaska Pipeline's Life Span
<http://www.law360.com/articles/386371>

By Kaitlin Ugolik

Law360, New York (October 12, 2012, 6:21 PM ET) -- The oil giants that own the Trans-Alaska Pipeline System, two of its users and the state of Alaska reached a deal Thursday establishing the depreciation factors to use in setting TAPS rates and settling a long-running dispute over the pipeline's estimated life span.

In an agreement submitted to the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska for approval, the parties said they had agreed to accept the depreciation rate used in the TAPS carriers' FERC and RCA filings that are subject to refund for periods prior to Jan 1, 2013.

The resulting rate depreciation schedule shows the life span of the pipeline ending in 2045, a compromise on both ends. The carriers — BP PLC, ConocoPhillips, Exxon Mobil Corp., Chevron Corp. and Koch Industries Inc. — sought to adopt FERC's original 2034 end date, while two users — Anadarko Petroleum Corp. and Tesoro Corp. — wanted to push the span to 2068.

"If ... FERC approves and the RCA accepts the agreement, without modification or conditions, then the issue of which depreciation factors to use in setting TAPS rates, and hence the appropriate life of line, will be settled with prejudice in the [pending] FERC and RCA dockets," the parties said.

The dispute stems from the pipeline owners' attempts to recoup certain costs associated with a \$786 million reconfiguration project from Anadarko and Tesoro, including the replacement of certain natural-gas- and liquid-fueled turbines with electric versions. Anadarko and Tesoro have objected to the rate increases, including a 10 percent hike in 2010, arguing that the oil giants mismanaged the planning, design and development of the reconfiguration project.

In 2008, FERC adopted an end-of-life date of 2034 for the pipeline. But in a 2010 property tax dispute, an Alaska state court found the pipeline could continue operating economically until 2067 — a ruling that, if adopted by FERC, could dash the carriers' dreams of higher rates. The parties disagreed over how much weight the tax ruling should have, and in a Feb. 6 order a chief judge ruled that it was "not dispositive of the end-of-life issue in these proceedings," leaving it to the presiding judge to determine.

A shorter life expectancy would boost prospects for approval of rate increases, because the carriers would have less time to recoup their investment. A longer life span could eliminate the rate hikes and require the companies to reimburse shippers for the difference.

In connection with Thursday's agreement, should it be approved, all rates subject to refund in proceedings at FERC and RCA will receive revised tariffs that will change the ongoing subject-to-refund rate by incorporating the agreed-upon settlement depreciation factor of 3.125 percent for year 2013. For 2014, the depreciation factor rises to 3.226 percent; in 2015, to 3.333 percent, and so on.

The deal will initially last for five years, giving the settling parties an option to revisit the depreciation factors for TAPS rate-making after it expires.

Though an agreement on depreciation factors and the pipeline's end-of-life date knocks down two major hurdles in the case, the settlement does not resolve any of the other issues pending in the parties'

FERC and RCA proceedings.

Counsel for the parties did not immediately respond to requests for comment Friday.

Anadarko and Tesoro are represented by Robin Brena, David Wensel and Laura S. Gould of Brena Bell & Clarkson PC and Joseph Koury, Jeffrey DiSciullo and Andrew Swers of Wright & Talisman PC, as well as in-house counsel Sherri B. Manuel and Barron W. Dowling.

ConocoPhillips is represented by Steptoe & Johnson LLP and Kemppel Huffman & Ellis PC. ExxonMobil is represented by Sidley Austin LLP and Patton Boggs LLP. BP is represented by Vinson & Elkins LLP and Guess & Rudd PC. Koch Industries is represented by GKG Law PC and Birch Horton Bittner & Cherot. Chevron subsidiary Unocal is represented by Hogan Lovells.

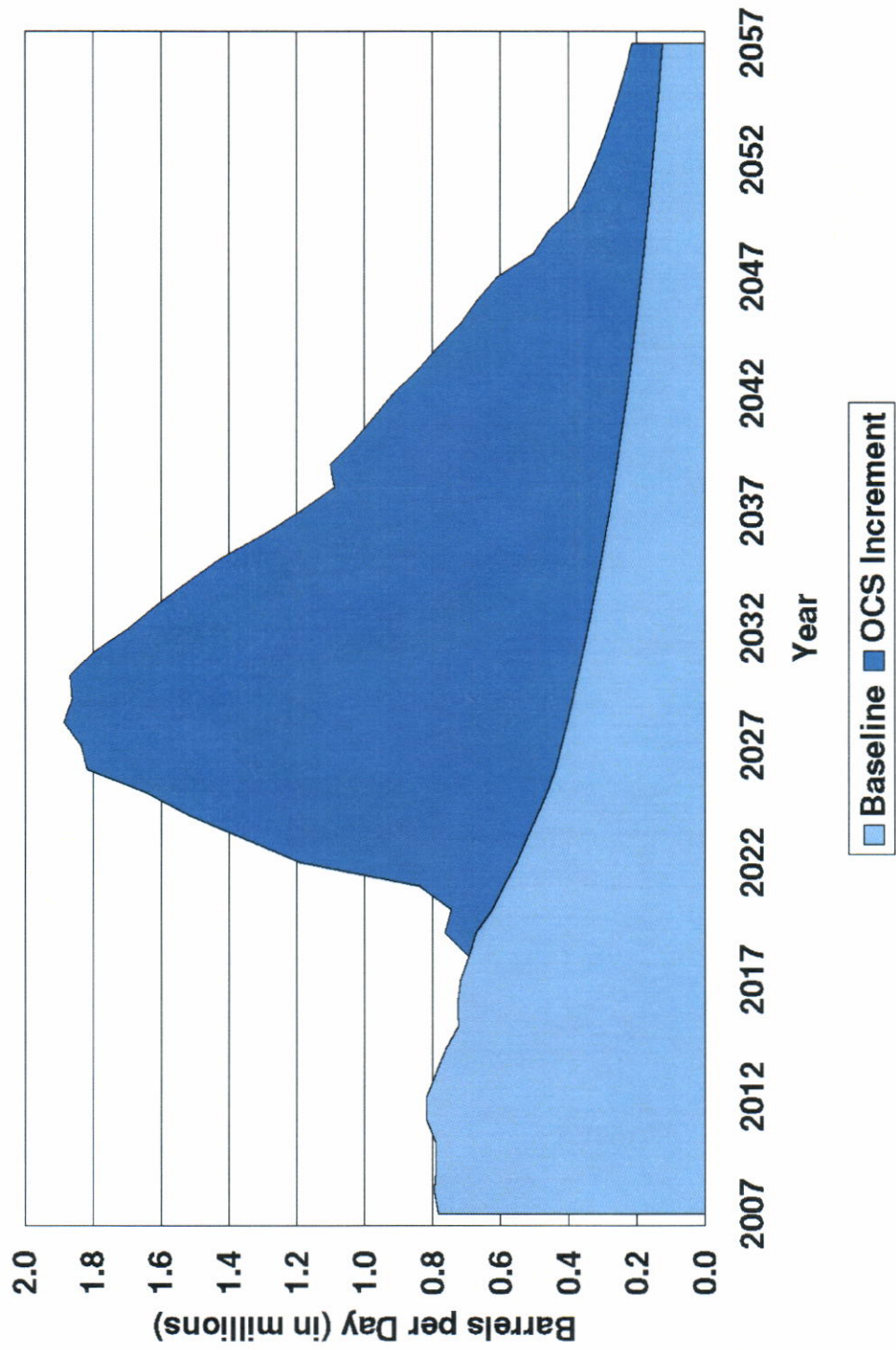
The cases are docket number IS09-348, before the Federal Energy Regulatory Commission, and docket number P-08-009, in the Regulatory Commission of Alaska.

--Additional reporting by Liz Hoffman. Editing by Elizabeth Bowen.

The Life of TAPS

Reserves and Throughput

Oil Production with OCS



THE LIFE OF TAPS - Reserves and Throughput

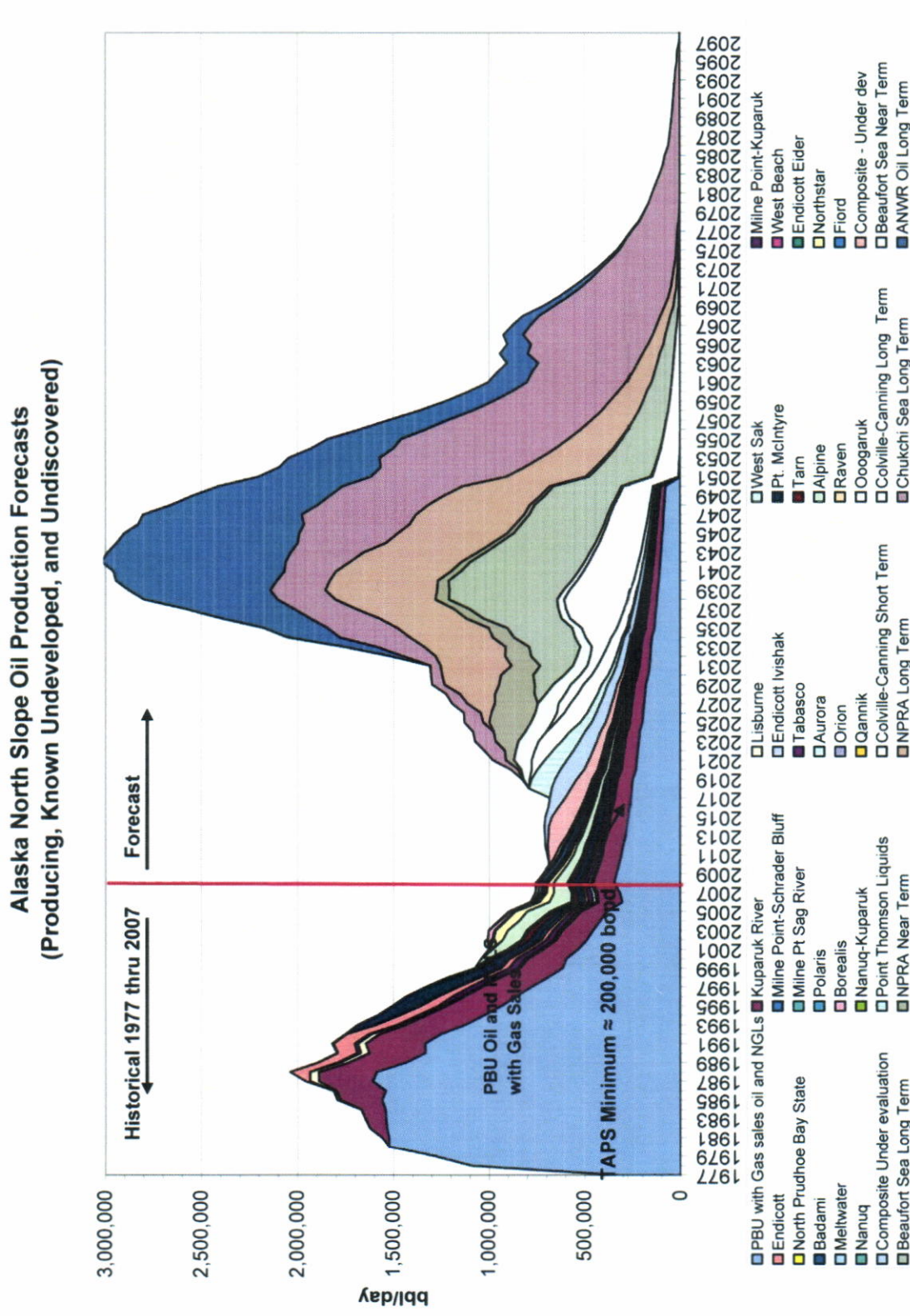


Figure 3-55. Alaska North Slope historical and forecast oil production from producing fields, known undeveloped fields, and undiscovered fields.

MUN7-0014 at 10 (Hite)

Excerpts from From case No. 3AN-06-08446 (Consolidated) Decision 30 Dec 2011

Assertion: Oil is declining and the pipeline might shut down.

Fact-Check:

Court documents reveal that oil companies think the pipeline will continue in service beyond 2050 to perhaps 2064, a far cry from the threat of imminent pipeline shutdown. p. 138 of 213.

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

Minimum pipeline throughput projections were based on levels as low as 70,000 to 100,000 barrels per day (bpd) even though recent years of propaganda have stated that TAPS would cease to operate at about 300,000 bpd which would be reached around 2025 if the current decline estimates continue. From case No. 3AN-06-08446 (Consolidated) Decision 30 Dec 2011 p. 143 of 213.

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.

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.

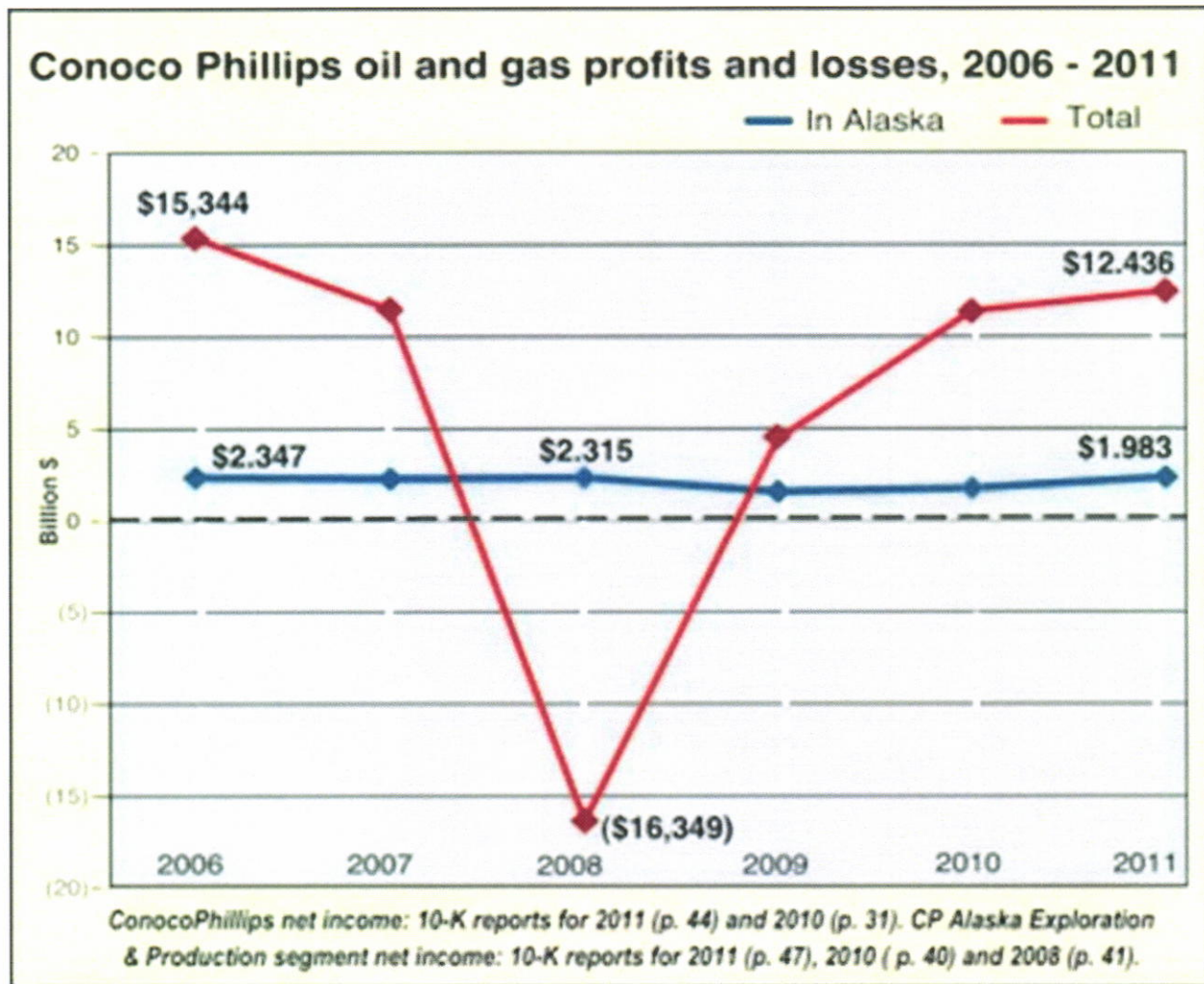
p. 136 of 213

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

There is so much oil, booked as reserves on the North Slope that the current pipeline will continue past 2050, or be rebuilt if necessary. From case No. 3AN-06-08446 (Consolidated) Decision 30 Dec 2011 p. 42 of 213.

economic value of TAPS.¹⁰⁰ 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.



Richard A. Fineberg (Research Associates), October 2012