SB
305
(FILE 11)

Testimony Before the Senate Resources Committee

My name is Michael D. Williams and I am the Chief Economist for the Alaska Department of Revenue. I have lived in Alaska for a little over a year and I do not know all of you in this room. I have been in the oil gas business for over 20 years in various capacities including being an Economic Advisor to the Saudi Arabian Minister of Finance, a Principal Administrator with the international Energy Agency in Paris, and an Economist with Marathon Oil Company. I have operated my own consulting company at different times in my career and [as part of my work], conducted the empirical analysis for the Pulitzer Prize winning book "The Prize" by Daniel Yergin. My education includes a Ph D in economics and I wrote my Ph D dissertation on Alaskan natural gas.

The purpose of my talk today is to discuss future crude oil production volumes in Alaska, but before I do that I want to examine some of our earlier forecasts. An examination of our forecasts reveals that we usually over-estimate production volumes [see chart #1 & Explain]. There are two main reasons for this error and they are the following:

- **Maturity of the Prudhoe Bay field** – The field has been producing oil for close to 30 years and is subject to problems associated with an aging field. Thus, leaks in pipelines – such as what occurred on Thursday – and other events are more likely to occur. To reflect this reality, our production rate for future years has been decreased at Prudhoe Bay.
- **Difficulties Developing "Heavy Oil"** – dealing with the viscous oil on Alaska's North Slope requires new techniques and technologies. Because of the issues dealing with viscous oil, many of the viscous oil projects have been delayed as the oil companies attempt to figure out the best way to deal with this gooey substance. To reflect reality, the speed with which the production from heavy oil comes on-line in our forecast has also been delayed.

For the spring 2006 forecast, the Department of Revenue continues to make adjustments to our production expectations from the North Slope. In the near term, we have incorporated revised reservoir performance analysis on declining fields, reviewed the uncertainty associated with the pace and scope of developing satellite fields and re-evaluated unplanned downtime at all fields, especially Prudhoe Bay, resulting in a net reduction, on average, of

about 30,000 barrels per day over the next five years. Roughly half of this reduction is attributed to reservoir performance and facility related downtime and half is related to the pace of development of heavy oil, primarily at West Sak. We now forecast ANS production to average slightly above 800,000 barrels per day for FY 2007 through FY 2011.

North Slope crude oil production is characterized in three ways, each with discrete, albeit estimated confidence levels: (1) currently producing, (2) currently under development and (3) currently under evaluation. We do this so that you will have an understanding about the uncertainty associated with the production forecast. We continue to forecast production of only those reserves that have already been discovered and at minimum are being evaluated for development.

Oil production in Alaska is forecast to decline at a rate of about 6% in FY 2006 and about 1.5% per year thereafter [see chart #2 & Explain]. I will now describe the forecast categories in this chart.

- Production characterized as "currently **producing**" includes baseline production and presumes a continued level of expenditure sufficient to promote safe, environmentally sound operations. Such expenditures include the following: well diagnostic and remedial work, data acquisition and rate-enhancing expenditures such as perforating, acid stimulation, well work-overs, fracture treatments, artificial lift optimization and production profile optimization. This category of production also presumes continued gas and water injection for pressure support. Based on historical forecasting performance, we assign a 98% confidence level for the current fiscal year.
- Production characterized as "currently **under development**" is based on new projects currently funded and in the design/construction phase, as well as development drilling and enhanced oil recovery (miscible or immiscible injection) projects, currently funded or underway, but not included in the "currently producing" category. It also includes incremental oil expected from the long-term gas cap water injection project at Prudhoe Bay and the low salinity water-flood at Endicott. Examples of production "currently under development" include the Fiord and Nanuq satellites at Alpine, remaining J-Pad development at West Sak, development drilling at Schrader Bluff and certain satellite development at Prudhoe Bay. We have slowed the pace of development at all heavy oil fields to allow proper mitigation of

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challenging commercial and technical issues. Because of timing and scope uncertainty, our subjective confidence for this category of production is approximately 80-85%.

- Production characterized as "currently **under evaluation**" includes technically viable projects currently in the "pencil sharpening" stage where engineering, cost, risk and reward are all being actively evaluated. These projects are all currently unfunded by the operators but have a high chance of being brought to fruition. They include enhanced oil recovery at certain satellite fields, development drilling outside the core areas at West Sak and Schrader Bluff, expanded development at Prudhoe Bay satellites Orion, Polaris and Borealis and Alpine West development. Also included in this category is NPR-A development, Point Thomson, Liberty and development of other known onshore and offshore discoveries. Regarding NPR-A, we are forecasting production from four small 'puddles' in the vicinity of known discoveries currently named 'Lookout', 'Moose's Tooth', 'Spark' and 'Rendezvous'. Since these discoveries have been announced, there has been ongoing exploration outside the boundaries of these accumulations, and explorers continue to push further west in search of new development opportunities. Confidence levels vary for this category of production. Certain heavy oil development drilling for Schrader Bluff, Orion or West Sak in 2007 might have confidence levels approaching that of "production under development". Offshore developments such as Liberty, or potentially high cost, scope challenged developments such as Point Thomson probably deserve lower confidence, and our subjective assessment is in the 70%-75% range. All production from this category is subject to delays and scope changes that might impact reserves or production rates.

There are many details surrounding this forecast which are based on petroleum engineering knowledge – and I am not an engineer. In addition, I have only lived in Alaska for a year so I do not have the in-depth knowledge that he has. Our petroleum engineer prepared the forecast, and, for the more involved questions regarding geology and engineering, I will turn to our engineer for support.

Developing crude oil resources is capital intensive and will require significant investment in time and capital. The Governor's proposal tax system – the PPT – creates a fiscal framework that provides strong incentives for

exploration and reduces the risks and capital costs of development. Most importantly, it provides a long term revenue stream to the State by encouraging new participants and supporting new development.

This concludes my remarks and I will attempt to answer your questions.

Here are the Questions that remained to be answered by DOR (from March 2-3, 2006)

1. "look-back" – excel files to be provided.
8. progressivity structure for tax – not yet answered
11. claimed expenses under sb 185 – table to be provided
14. terms – they requested clarification from us
17. check on the order of credits to be applied
18. during discussion with outside law firms, did it change any of the bill provisions?
20. See #1
21. similar to question in #18.
22. define point of production - to be provided
23. gas treatment-processing facilities – to be provided.
24. get a list of the cases
25. historical analysis – to be provided
27. AS 43.55.160(j) -- to be provided
29. estimates of undiscovered resources – to be provided
31. Net Profit Share Leases – to be provided
37. to double check the sentence "Currently there is no "free use of oil" to produce more oil in statute.
40. other nations with profit system – to be provided
41. "true-up" issue – to provide more info on this.
49. estimated economic impact – to be provided
54. section 21, page 1, line 8 – to be provided.
57. clarify – some of the named had a tax when they exceeded the named value
58. language clean up – typo's sentence repeats.
66. oil field needs – to be provided

67, 68, 69, 70, 71 and 72 - to be provided

March 7, 2006

Senator Tom Wagoner, Chair
Senate Resources Committee
State Capitol, Room 427
Juneau, AK 99801

Rep. Ralph Samuels, Co-Chair
House Resources Committee
State Capitol, Room 126
Juneau, AK 99801

Rep. Jay Ramras, Co-Chair
House Resources Committee
State Capitol, Room 104
Juneau, AK 99801

Re: Questions on PPT Legislation (SB 305, HB 488)

Dear Senator Wagoner and Representatives Samuels and Ramras,

This letter contains our second interim series of questions and answers related to the above-reference legislative bills. We have listed below only those items for which we have provided answers, or provided additional information, since Friday, March 3, 2006.

1. Identify values/amounts for the "look-back" or transitional section; per year according to the actual, by type (exploration, development, production).

The Department of Revenue model uses $1 billion per year as capital costs, so for the transitional period, there would be about $5 billion. This annual costs are based on compilations of historical data.

(millions $)	Exploration	Development	Total
2001	152	1,636	1,788
2002	125	1,054	1,180
2003	90	970	1,060
2004	67	980	1,047

8. Which other tax regimes – worldwide - have a progressivity structure?

Progressive features are relatively common around the world. Following is a list of the main fiscal regimes with such features. "Old" features are defined as features that have been in existence for more than 20 years. "New" less than 20 years.

There is a wide variety of systems that are progressive with the level of well production or field production. These systems are not included in the list.

Country	Region/Type	Feature	Oil/Gas	Old/New
Canada	NWT	IRR based profit sharing royalty	Both	Old
	Newfoundland	IRR based profit sharing royalty	Oil	Old
	Nova Scotia	Payout based profit sharing royalty	Both	New
	Alberta	Production/Price sensitive royalty	Oil	Old
	Alberta	Price Sensitive royalty	Gas	Old
	Alberta oil sands	IRR based profit sharing royalty	Oil	Old
Colombia		Price sensitive windfall profits tax	Oil	New
Venezuela	Conventional Oil	IRR based profit share	Oil	New
Peru		R-factor royalty	Both	New
Bolivia		Profit sensitive Surcharge with uplifts	Both	New
Trinidad & Tobago	Conventional Oil	Supplemental Petroleum Tax, Price sensitive	Oil	New
	Deep water	Production/Price sensitive profit oil/gas shares	Both	New
Norway		Uplifts on Hydrocarbon Tax	Both	Old
UK	Old licenses	Uplifts and Oil Allowance on PRT	Both	Old
Denmark		Uplifts on Hydrocarbon Tax	Both	Old
The Netherlands		Uplifts on Special Profit share	Both	Old
Algeria		Cumulative Revenue sensitive PRT and uplifts	Both	New
Tunisia		Sliding scale taxation	Both	New
Libya		R-factor based profit oil splits	Oil	Old
Nigeria		Uplifts and tax credits	Oil	Old
Angola		IRR based profit oil shares	Oil	New
Qatar		R-factor based profit oil	Oil	New

		shares		
Saudi Arabia		IRR based corporate income tax rates	Gas	New
Iran		Buy Back contracts	Both	New
Pakistan	Offshore	Price Sensitive Windfall profits tax	Both	New
India		R-factor based profit oil shares	Both	New
Thailand		Profit sensitive SRB	Both	New
Malaysia		Price sensitive windfall profits tax	Both	Old
Indonesia		Uplifts	Both	Old
Australia	Offshore	IRR based PRRT	Both	Old
PNG		IRR based APT	Both	Old
Russia	Sakhalin	IRR based profit oil shares	Both	New
Kazakhstan	Tengi.	IRR based profit share	Oil	New
	General	New models with variety of progressive features	Oil	New
Azerbaijan	AIOC	IRR based profit oil share	Oil	New
	Other	R-factor based profit oil shares	Oil	New

11. Provide information on the effect of previous incentives – the costs.

Claimed expenses under SB 185 (43.55.025) totaled $104. 8 million and claimed credits total $33. 6 million [see table below]. A claim was received by the Department of Revenue last week, thus the totals has been updated from the $95.5 million and $29.0 million figures previously provided.

	No. of Projects	Claimed Expenses	Claimed Credits
Audited & Issued:	7		
N. Slope wells		$51,050,000	$13,308,000
Cook Inlet wells		$ 3,430,000	$ 392,000
Cook Inlet seismic		$ 3,178,000	$ 1,085,000
Audits In progress:	5		
N. Slope wells		$26,615,000	$10,646,000
N. Slope seismic		$ 7,957,000	$ 3,182,000
Other - seismic		$ 3,295,000	$ 1,318,000
Other - wells		$ 9,286,000	$ 3,714,000
Total	12	$104,811,000	$ 33,646,000

18. The State of Alaska has relied on the services and expertise of multiple outside law firms to handle disputes over oil and gas issues; have you conferred with such counsel in the drafting or review of this legislation? If so, have they assessed the impacts of the legislation on the State's legal position in past agreements, current disputes, or future disputes?

Yes, such counsel (not all of them) have been consulted and such assessments have been discussed but have not generally been generated in formal written form.

Did such advice result in any changes to the legislation?

The bills reflect discussions with counsel that took place during the drafting process, so in that sense such advice did affect the legislation.

24. What standard will be used to determine whether oil or gas is of 'pipeline quality' under the definition of 'gross value at the point of production'?

The current production tax statute taxes the "gross value at the point of production" of oil and gas. The quoted phrase was enacted in 1977 and replaced the previous statutory phrase "gross value at the well." This change was aimed at ensuring that costs of production operations downstream of the well would not be deductible in calculating the taxable value of oil or gas; rather, taxable value would be calculated at the point that production is complete.

In the case of oil, "gross value at the point of production" was defined as the value of oil where it is metered "in a condition of pipeline quality," and "pipeline quality"

was defined as "good and merchantable condition." This definition essentially adopts commercial standards of marketability for oil. HB 488 and SB 305 would simplify and shorten the definition of gross value at the point of production for oil but do not materially change it. In addition, the definition of "oil" is broadened to include liquid hydrocarbons recovered by gas processing in the case of leases or properties whose production is subject to gas processing. The bottom line is that the point of production under these bills would still be the point where oil is metered in a condition of pipeline quality, and "pipeline quality" would mean the same thing it has always meant under the production tax statute.

In the case of gas, neither the existing statute nor the new bills use the phrase "pipeline quality" or "good and merchantable condition" with respect to gross value at the point of production. Rather, the statutory definitions of "gross value at the point of production" for gas, as interpreted and clarified by the Department's regulations, 15 AAC 55.900(a)(6)(B) and (C), focus on where gas is accurately metered after separation from oil. The new bills retain this concept but, in effect, expand "separation" to include gas processing, so that in the case of leases or properties whose production is subject to gas processing, the point of production for gas recovered by gas processing is the point where it is metered downstream of the processing.

25. Provide a historical analysis of the results of valuation methodologies adopted by the Department of Revenue, Department of Natural Resources (under all agreements), and the Department of the Interior.

While there is much that is parallel in the calculation of gross value at the wellhead between Royalty and Tax, many differences have developed. Both start with destination value in the market, and then subtract the tankering, pipeline and other costs to arrive at a well head value. The Department of Revenues valuation for Tax comes from statute and regulation. The Department of Natural resources valuation for royalty comes from lease contracts supplemented by Royalty Settlement Agreements (RSAs) which set forth different methods for each large North Slope producer. (Cook inlet valuation is not covered in this answer.)

Destination value, for the Department of Revenue is what the oil was sold for, or when the oil is not sold or is sold for a below market price, the so called prevailing value or spot price. Destination value for the Department of Natural Resources is a formula driven by the ANS or a basket of similar crudes.

From the destination value, each method subtracts marine transportation costs, TAPS costs (including tariffs, losses and quality bank changes from mid-point refineries), feeder line costs (including tariffs, losses and quality bank differences), and other miscellaneous costs. DOR deducts the costs specific to each taxpayer, while for royalty, some of the RSA have formulaic deductions and others use the royalty

payers' actual cost. In addition, DNR subtracts field costs for most DL-1 lease form leases on the North Slope whereas DOR does not.

The differences between wellhead values narrow across time. The average difference for the period FY00 through December 2005 is 3.9%. However, the average difference for the last 12 months is 6.1% while the average difference for FY00 through FY03 is 3.0%.

The critical point is that DOR uses actual proceeds, and only resorts to Prevailing Value when the conditions of 020 (f) are met, thereby taxing on the higher of proceeds or PV. For each of the three producers, DNR uses a single destination formula based on spot prices, not actual proceeds.

34. Of the pre-PPT credit provisions (the claw back), how many investment credits were sold under SB 185 and how do we ensure the person who holds the credit, not the original recipient, gets the credit?

a. Only 2 credits that have been issued have been sold to another party.

b. The Division will first obtain a waiver of confidentiality from the seller allowing the Division to confirm the credit amount to the prospective purchaser. Once sold, the Division makes the transfer and issues a new credit certificate to the purchaser upon receipt of documentation and confirmation of the transaction from the seller of the credit. The credit exists as an electronic entry in a Division database, therefore only the Division can make the actual transfer of the credit in that database. A new certificate is entered in the database to the purchaser and the old certificate is marked as transferred and its balance is zeroed out. The Division then notifies both the purchaser and the seller, in writing, of the completed transfer of the credit, at which time the purchaser may then apply the credit to its own production tax liability. When a credit is applied to a tax liability by a producer, the Division then verifies the holder and amount of the claimed credit against the credit certificates in the database.

40. Do other nations with a net profit system have the 90 percent payment of taxes with the sure-up provision the following year? What is the economic impact of this change?

a. Net profits systems in the world typically work on the basis of three different concepts:

(a) monthly payments based on actual production, revenues and expenditures, without an annual true-up, as is the case in most production sharing agreements
(b) yearly payments based on a yearly return, filed within a few months after the year, without a need for monthly payments on account, as is the case for the Thai SRB, for instance. This means there is only a single annual payment.

(c) Yearly payments based on a yearly return, filed within a few months after a calendar year or a lease/contract year, with monthly payments on account. In this last case, the monthly payments could be based on:
   a. Estimates for each month, as for instance with the Nova Scotia profit sharing royalty. These estimates can be challenged by government and different estimates may be required.
   b. Payments based on a mixture of actual information from the previous month and estimates, such as in Algeria
   c. Corporate income tax style procedures, whereby payments are based on taxes paid in the prior year (Norway for the Hydrocarbon Tax).

The 90% rule proposed for Alaska is unique. The overall economic impact would depend on the taxpayers' cost estimates for each month. We expect that taxpayers will experience underpayments in some months, but will experience overpayments (because of estimates used) in other months. In addition, falling production amounts, or unforeseen costs will serve to likely create overpayments in later months. Overall, we do not expect any material net economic impact.

66. The discussion of oil field needs, i.e. not to deplete the gas pressure, did not recognize the CO_2 re-injection. How will that lengthen the field life(s) and at what volumes, i.e. how will it affect taxes?

At Prudhoe Bay about 8.5 billion cubic feet of gas a day is reinjected into the field for pressure maintenance. After stripping out certain hydrocarbon liquids, CO2 is reinjected along with the other hydrocarbons (and non-hydrocarbons). When an export line is built on the North Slope, the CO2 will be stripped (in "gas treatment"), and there is some question about what will happen with that CO2?

67. What happens if the "Big Three" sell off their assets to 20 smaller companies? Will the significant tax benefits ever be realized?

Assume 20 new companies suddenly showed up on the North Slope and each qualified for the 73 million dollar allowance. A total of 1.4 billion dollars in profits would be sheltered from taxes. If these companies had simply purchased their way in, then taxes would be lower by $280 million (20% of 1.4 billion) than they would be otherwise. At current prices, or say even at $40 oil, this could be a material portion (though not all) of the tax.

If that is the future of the North Slope and the sell off was for business purposes, the legislature may choose to act and make it less attractive to new firms coming in. If these were tax motivated sales, we hope the powers of the commissioner that are built into the bill would prevent the new entrants from using the $73 million allowance

73. Will the new confidentiality provisions extend to or have an effect on any other taxes besides the production tax.

The new confidentiality language added by secs. 4 and 16 of the bill applies only to information relating to the oil and gas production tax, not other taxes. This is because:

(1) AS 43.55.040(1) addresses information "necessary to compute the amount of the tax," and the phrase "the tax" is used throughout AS 43.55 as referring only to the production tax; and

(2) AS 43.55.040(1) deals only with information obtained from persons "engaged in production," or their agents, and with purchasers "of oil or gas," and with owners of a "royalty interest in oil or gas."

77. How much gas was flared so as to trigger taxes and/or penalties in recent years?

During FY 2005, 351,000 Mcf of gas was flared that was considered gross taxable production. Of that, only 120,000 Mcf was from fields with a positive ELF and subject to tax. During the same period 31,000 Mcf was flared and considered waste and subject to both tax and penalty.

80. When the 1989 ELF change was enacted, was it retroactive and were there transition provisions?

The 1989 ELF changes were made retroactive to January 1, 1989, and applied to oil produced after December 31, 1988. There was a transition provision to the effect that tax payable as a result of the retroactive changes would be due on the 20th day of the calendar month following the effective date of the Act. (The effective date of the Act was August 6, 1989.)

82. Under the new gas and oil definitions what will the net change to the spill fee be? In other words, looking at FY 2005, how much, if any (a) oil did we tax for its use in production operations and (b) how many ngls were put in TAPs?

During FY 2005 tax was collected on 1,222,400 barrels of crude oil used in production operations. During FY 2005 16,445,000 barrels of NGLs were put in TAPS.

83. For sales of credits by the smaller interests, estimate the price at which those credits will no longer have a market among the big three.

Credits may be used in the year of expenditure, carried forward to following years, or transferred (they are fungible). If transferred, the credit can not lower a severance tax rate below 80% of what it would otherwise be (AS 43.55.024(e)). These credits will have market value that would not exceed 20% of their face value ($1,000 in capital expenditures would save $200 in State severance taxes). A company generating them but unable to use them would face a choice – sell them or use them the following year (if they have taxable income).

Use the next year reduces the value of the credits due to discount rate. Oil companies typically try to use a 15% discount rate but will often settle for less, say 10%. This means, all other things equal, they would be willing to sell a $1,000 credit ($5,000 capital expenditures) for $900 (10% discount rate) or more. Conversely, another company would be willing to pay up to $999 for the credit to save $1,000 in State severance tax.

If we assume a billion in spend assume that 10% of that was for little companies that would want to sell their credits, so 200 million in credits are for sale. With our 20% limit, that implies that if the big three had a billion dollar in tax obligations, that market could absorb all the credits. As our fiscal note shows, if the price of oil is $40 or above, all of the credits would be usable in the immediate year. If oil falls below $40, then we expect that the credits would be fully utilized within two or three years. While the time-value of money means that those certificates would be discounted, we believe that the certificates would still be marketable.

84. If aggregation at Prudhoe Bay had been implemented on July 1, 2001 [the start of the claw back period], how much more would the State have received between then and the actual aggregation date?

The State would have received $430.4M additional revenue. See estimates below:

ANS Oil Severance Tax
With and without aggregation of
PBU
FY2001 thru Jan 2005 Production

FY	No Agg	With Agg	Delta
2001	667.1	713.1	46.0
2002	444.5	501.2	56.7
2003	549.6	644.4	94.8
2004	594.5	720.4	125.9
2005	465.9	572.9	107.0
	2721.6	3152.0	430.4

Note: Estimate with Aggregation assumes all taxpayers are

paying under the aggregated Elf

85. Why are the status quo lines in the three graphs presented by Ms. Wilson flat once the forecast price effect is adjusted for? Wouldn't falling production and ELF move those down.

The status quo drops from $378 mm in 2009 to $291 mm in 2012. It looks flat because of the scale on the graph.

86. What will the actual cost to the investor be for these upstream investments, and what is the total government underwriting, state and federal, all tax types included. Is it different for large companies and small companies?

After state and federal tax, the investor would bear about 38% of the marginal capital. There is no reason to think it would differ appreciably between large and small investors.

87. Lord Browne famously said two years ago that any profits over $20 a barrel were being returned to shareholders as they weren't needed in BP's business. What tax rate, credit rate would be needed to have a cross over [unspecified period] at $20 [presumably Brent].

With a 20% credit it would take a tax rate of about 51% to affect a crossover at $20 Brent.

88. Please explain how the conservation surcharge is affected by oil price and what effect this bill has on the surcharge.

a. The conservation surcharge is a 3 cent per barrel charge on all oil produced less royalty barrels, so therefore it is not sensitive to price.

b. There will be changes in the quantity of oil subject to both production tax and conservation surcharges under the bill. One change will be positive, one negative. The positive change is that natural gas liquids extracted by gas processing and blended in the TAPS stream that are now taxed as gas, will be treated as oil under the bill. The negative change is that oil that is used in lease operations will not be taxed or subject to surcharge under the bill. Oil may be used to make fuel for lease operations and perhaps used for other production purposes. The overall result is an expected increase of the total surcharge amount of $444,000 per year, based on FY 2005 amounts. (See Question 82.)

The bill should not affect the assessment or collection of the surcharge, other than the quantity-of-oil effects described above. Any surcharge paid will be allowed to be

credited against production taxes, but that would only reduce the amount of tax collected, not the amount of surcharges collected.

89. Why are we including gas in the PPT calculation?

The bill includes gas in the PPT calculations because it is a stand-alone bill. The bill does not require implicitly or explicitly that a Stranded Gas Contract be subsequently concluded. Therefore, a PPT law would be entirely functional in case a Stranded Gas Contract is not presented to the Legislature or in case the Legislature rejects such a Contract.

The ELF system for gas is "broken". Just as the ELF is "broken" for oil, th gas ELF does not encourage reinvestment and it is not sensitive to price.

It should be noted that under high gas prices the Alaska State take for gas would increase significantly relative to the status quo. This would be beneficial in case significant gas reserves would be developed outside the scope of the Stranded Gas Development Act.

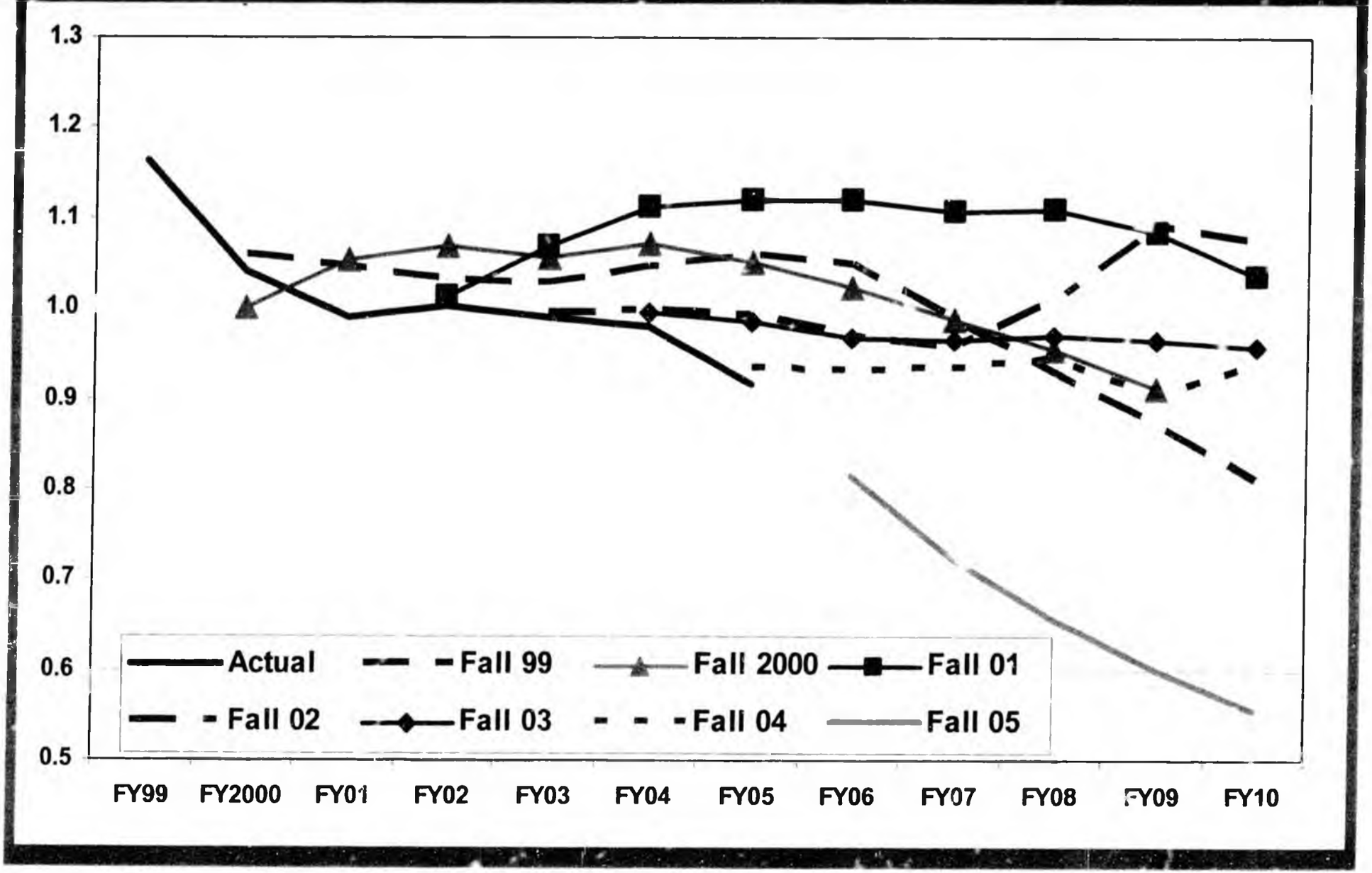
The inclusion of gas in the PPT is therefore a strong incentive for producers to conclude a Stranded Gas Contract that is in the interest of the State of Alaska. Including gas in the PPT enhances the bargaining position of the State for a good Stranded Gas Contract.

STATE OF ALASKA
DEPARTMENT OF
REVENUE

ANS Crude Oil Production Forecasts

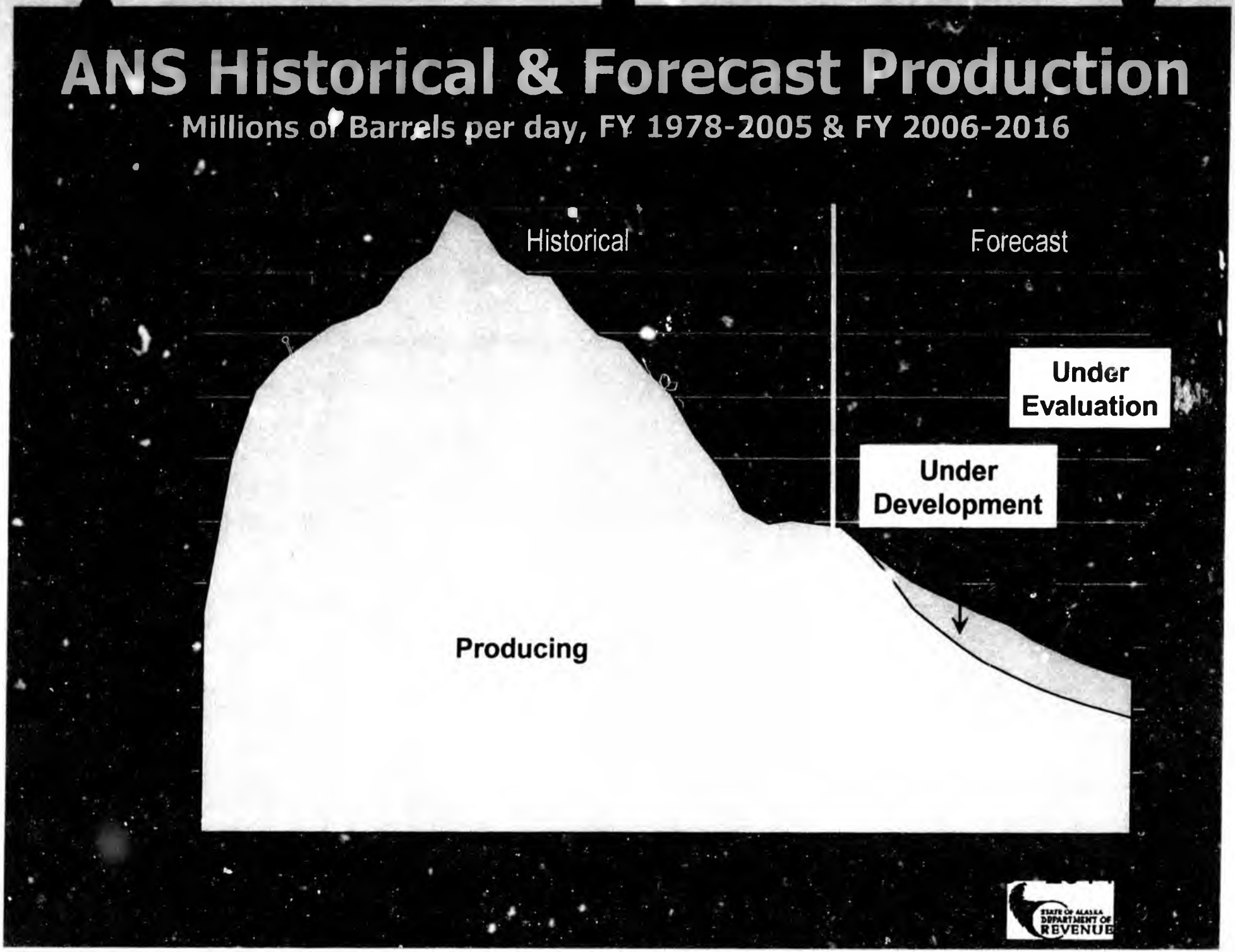
Fall Oil Production Forecasts

ANS, Millions of Barrels per Day



ANS Historical & Forecast Production

Millions of Barrels per day, FY 1978-2005 & FY 2006-2016



STATE OF ALASKA
DEPARTMENT OF
REVENUE

ANS Crude Oil Production Forecasts

Point of Production for Oil and Gas

Senate Resources Committee
House Resources Committee
March 7, 2006
Dan E. Dickinson, CPA

Oil or Gas – Why does it matter?

- Current rules
  - Gas taxed at 10% (times well based ELF) of gross
  - Oil taxed at 15% (times well & field based ELF) of gross
  - Free use of gas for production operations
  - (past production use of gas taxable)
  - Conservation surcharge on oil

Oil or Gas – Why does it matter?

- Proposed Rules
  - Gas and oil taxed at 20% of net
  - Free use of gas and oil for production purposes
  - (post production use of oil or gas remains taxable)
  - Conservation surcharge creditable

Oil or Gas – Why does it matter?

- Because the Point of Production is driven by the point of final separation

Point of Production – Why does it matter?

- Current rules
  - Costs incurred downstream of the point of production are deductible for calculating production tax.
  - Same effect for royalty except where defined field cost allowance

Point of Production – Why does it matter?

- If how costs were treated on either side of the point of production were identical it would not matter;
- But in switching from gross to net two different cost regimes.
  - Upstream outlays recaptured by 20% deduction and 20% credit for capital investment.
  - Downstream outlays recaptured through operating costs including depreciation.

Point of Production – Why does it matter?

- Yes – for a newcomer without heritage facilities, the cost difference is significant.

- May result in new facilities being built, or improve ability to access heritage facilities

Issues: combining production and post production facilities

- Current Rules
  - Central gas facility has post production activity (gas processing) & production activity (conditioning gas for pressure maintenance)
  - Had to allocate costs in plant because processing costs deductible

- Proposed Rules
  - Costs deductible (gas processing is production activity)

Gas or Oil?

- Oil
  - Must be in "condition of pipeline quality"
  - "Good and merchantable condition"
- Gas (in association with oil)

  first point accurately metered downstream from point of final separation

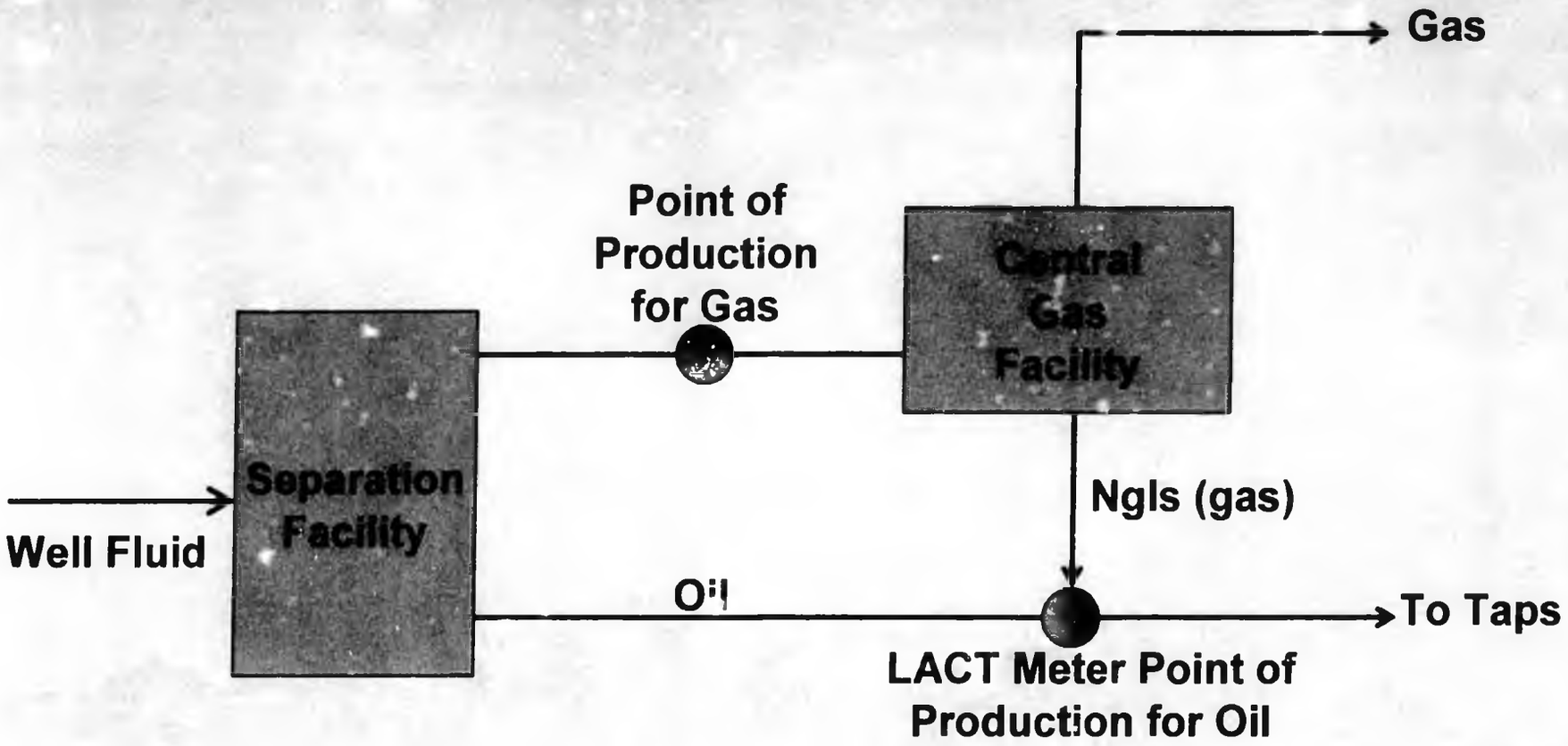
Why not a standard similar to oil?

Combining Gas Processing and Gas Treatment

- Current Rules
  - Both post production activities – no allocation of costs necessary
- Proposed Rules
  - may require allocation of costs.
  - Choice – could move gas treatment to upstream of point of production.

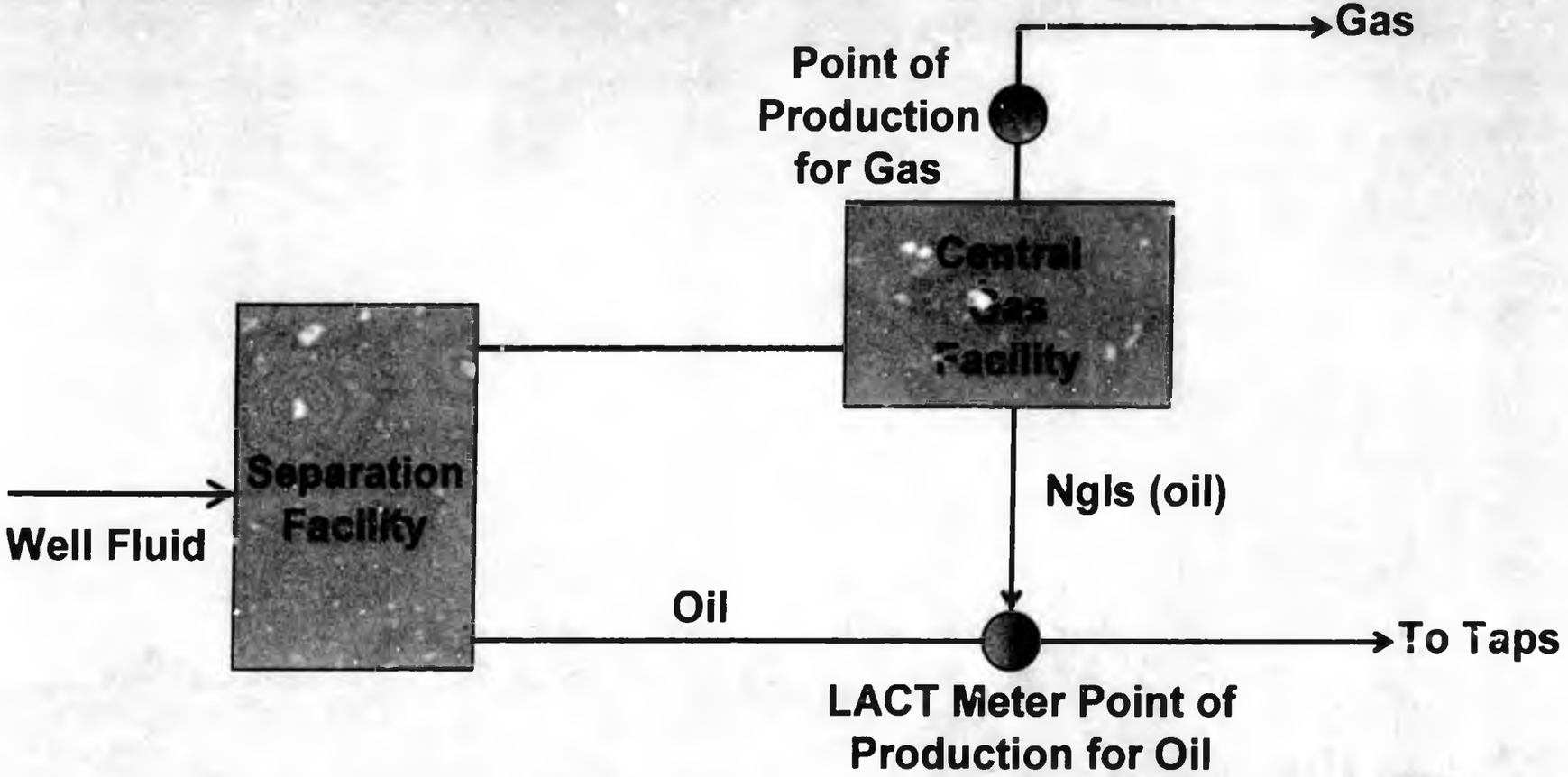
Prudhoe Bay: Point of Production

- Current



Prudhoe Bay: Point of Production

- Proposed



Goal:

- Simplified definitions that will not lead to low value-added conflicts
- Incentivize all production activity