SCOMM

117:4

ALASKA STATE LEGISLATURE

Joint Special Committee on Mergers

State Capitol
Juneau, AK 99801

Official Business

Chairman: Senator Rick Halford
Vice Chair: Rep. Joe Green
Senator Drue Pearce
Senator Johnny Ellis
Rep. Brian Porter
Rep. Beth Kerttula
Rep. Jim Whitaker

AGENDA
Tuesday, January 18, 2000
1:00 pm
Senate Finance Room

Presentation by Committee Staff and Consultants

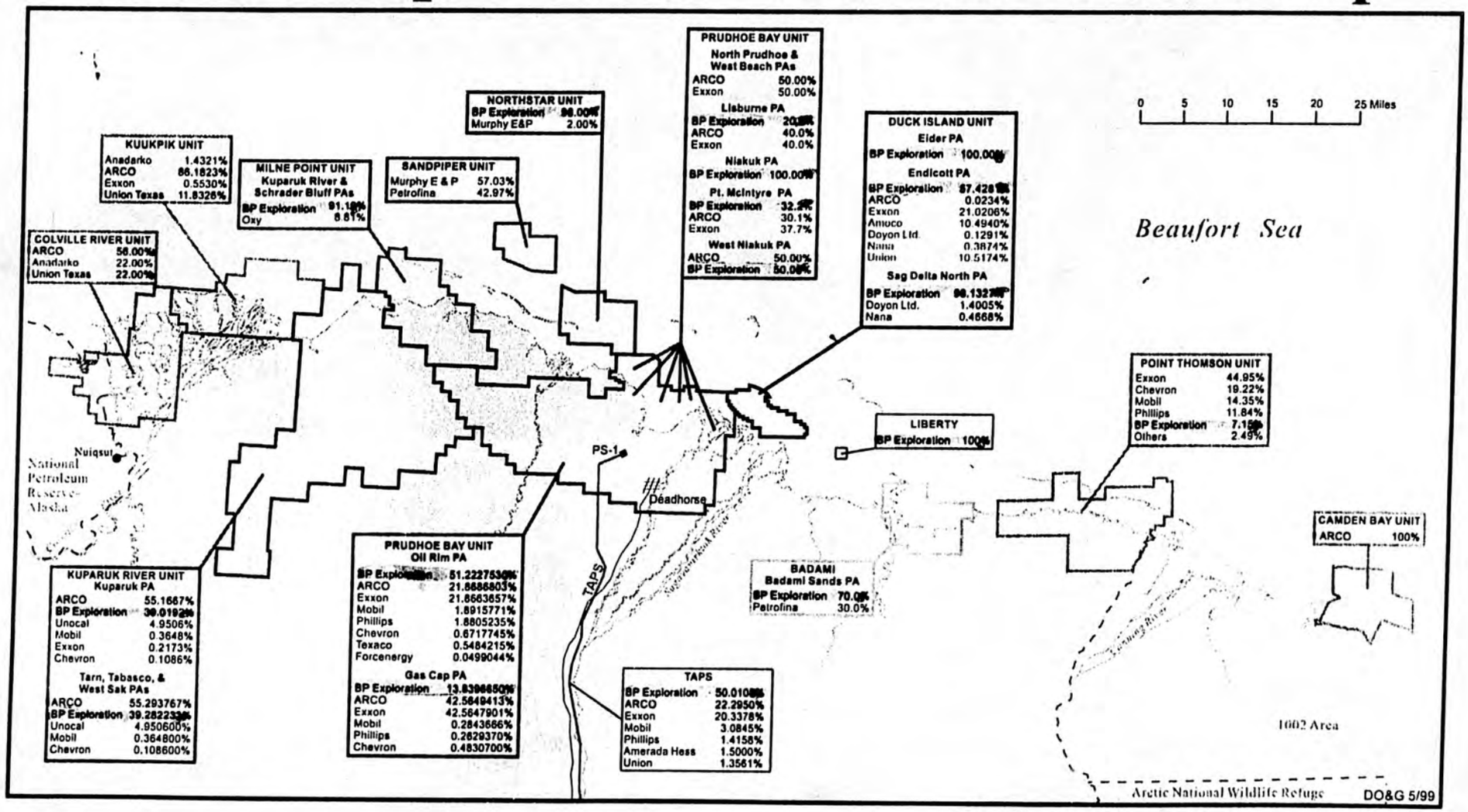
Fred Boness, Attorney, Preston Gates & Ellis

William MacLeod, Attorney, Collier, Shannon, Rill and Scott

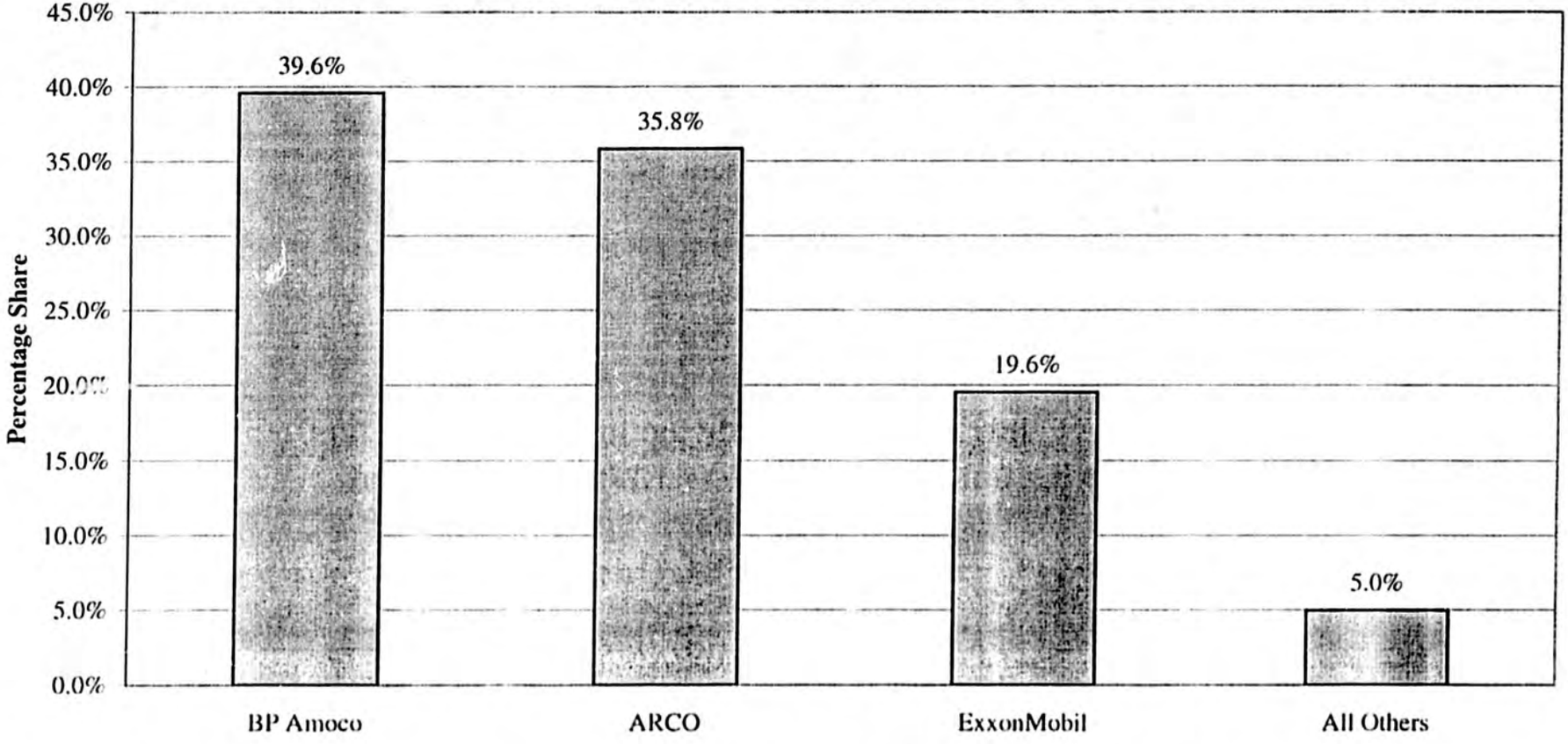
David Scheffman, Economist and Professor, Owen Graduate School of Management, Vanderbilt University

George Schink, Economist and Independent Consultant

North Slope Oilfield and Pool Ownership

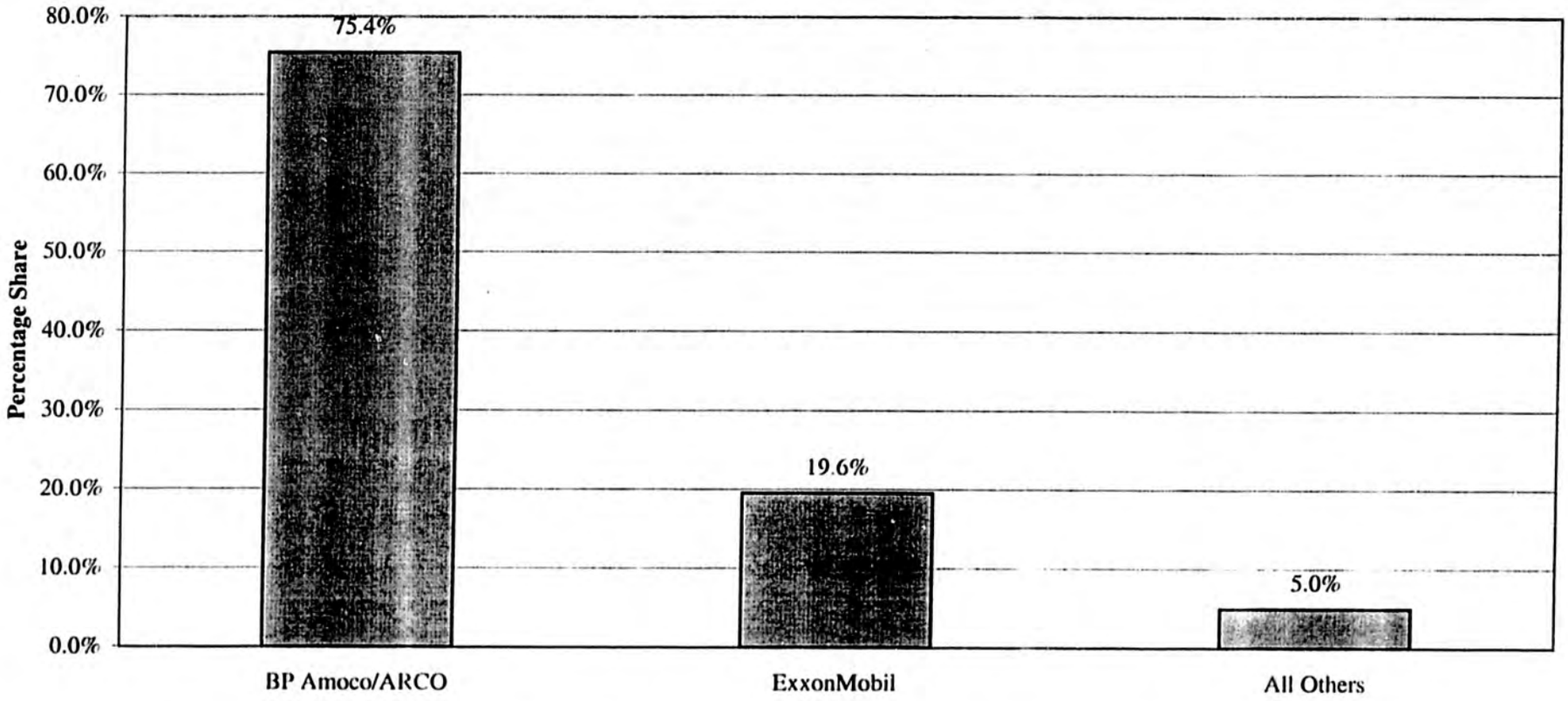


An Absent the Merger Comparison of
Estimated 2001 Percentage Shares of ANS Crude Oil Production
for BP Amoco, ARCO, ExxonMobil, and All Others
(Percentage Shares)



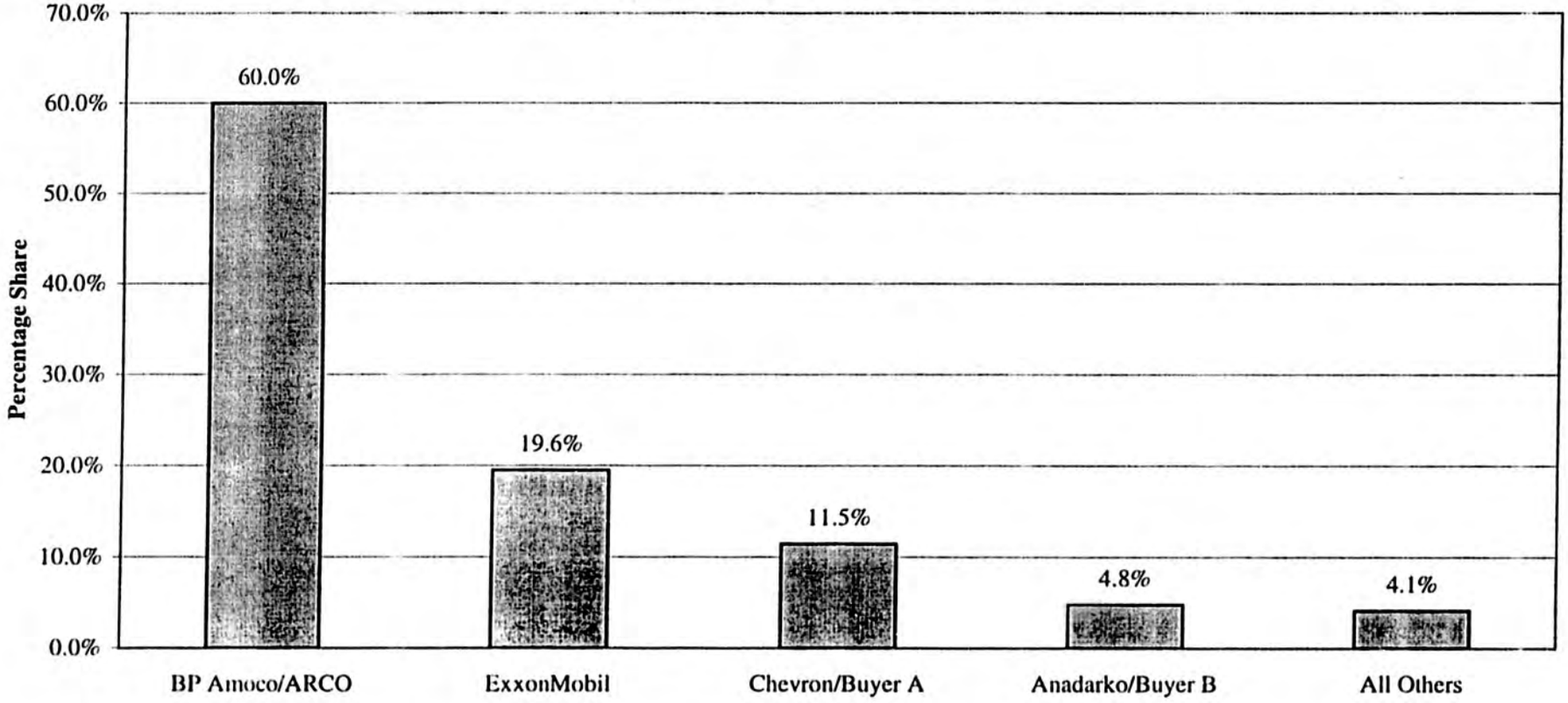
Sources: Alaska Department of Natural Resources, Historical and Projected Oil and Gas Consumption, May 1999; Charter for the Development of the Alaskan North Slope, December 2, 1999.

A With the Merger and No Divestitures Comparison of Estimated 2001 Percentage of ANS Crude Oil Production for BP Amoco/ARCO, ExxonMobil, and All Others (Percentage Shares)



Sources: Alaska Department of Natural Resources, Historical and Projected Oil and Gas Consumption, May 1999; Charter for the Development of the Alaskan North Slope, December 2, 1999.

A With the Merger and Charter Divestitures Comparison of Estimated 2001 Percentage Shares of ANS Crude Oil Production for BP Amoco/ARCO, ExxonMobil, Chevron as Buyer A, Anadarko as Buyer B, and All Others (Percentage Shares)



Sources: Alaska Department of Natural Resources, Historical and Projected Oil and Gas Consumption, May 1999; Charter for the Development of the Alaskan North Slope, December 2, 1999.

Oil and Gas Audit

Memo

TO: Wilson L. Condon
Commissioner of Revenue

From: Dan E. Dickinson
Director of Oil and Gas Audit

Date: January 13, 2000

RE: Effect of the Proposed Arco/BP Acquisition on Fall Revenue Forecast

I. INTRODUCTION

On December 2, 1999 the State and BP Amoco signed the Charter for the Development of the Alaska North Slope, setting forth the conditions upon which the State would support BP Amoco's proposed takeover of Arco. On December 8,1999 the Department of Revenue released its biennial revenue forecast. The report-in-hand, prepared by the Oil & Gas Audit Division of the Department of Revenue, discusses the effects of the proposed merger on the forecasted revenues. An important assumption underlying the forecast, as well as this analysis, was that the merger, if it occurred, would follow the plan outlined in the charter.

However, the merger now appears to be stalled before the Federal Trade Commission (FTC) in Washington. Either FTC or BP may take actions contrary to the key assumptions underlying the forecast. We have decided to go ahead and release this report, even though it must be viewed as a work in process. Some of the steps proposed to win FTC approval may well affect state revenue. I have speculated on some of these effects in this report. However, absent specific actions, I believe it is premature to perform specific analyses. We will of course supplement this report if and when there are changes on the merger front.

The State of Alaska, in its roles as sovereign and landowner, realizes revenue from the oil and gas industry through four mechanisms:

1. Oil and gas production/severance taxes – which are dependent on crude production levels and the value of the crude;
2. Oil and gas royalties – which are also dependent on production levels and the value of the product;
3. Oil and gas property taxes; and
4. Income taxes on the oil and gas industry.

Forecasts of these four revenue sources constitute the oil and gas portion of the department of revenue's biannual revenue forecasts. The division has analyzed each of these, as well as the underlying factors that affect them – value of crude oil, production and transportation costs, and production volumes – to try to understand the effect of the merger on Alaska's future revenue. **Based on this analysis, the division's conclusion is that the most likely effect from the merger on the first three revenue sources will be immaterial.** The division is unable to estimate the potential effect on state income tax from corporations in the oil and gas business. [1]

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[1] The department used its standard procedure without making any adjustments for the proposed merger or Charter to forecast state income tax revenue from corporations in the oil and gas business because it has proven very difficult, if not impossible, to forecast the discreet effects of the merger with any level of confidence. On the one hand, forecasters combined prior year returns from the merging companies and analyzed the resulting tax liability. This analysis suggests that income tax revenues may fall as a result of the merger. On the other hand, the purpose of the merger is to increase profitability, which ought to translate into increased taxable income and increased income tax revenue. While these effects may not precisely cancel each other out, they argue against making adjustments, in either direction, to our standard forecast procedure.

Why so little effect? There are three reasons:

1. The merger – either as originally proposed or as modified by the Charter – will not affect the anticipated production volume from currently known resources. The department's forecast of oil revenue – currently the primary source of Alaska's unrestricted revenue – has always been based on projected taxes and royalties for the anticipated production volumes from both 1) currently producing oil and gas fields and 2) discovered but not yet developed oil and gas reserves. Following a convention the department adopted more than 30 years ago, it has not included any revenues from future oil and gas discoveries in the fall revenue forecast. The department does not expect volume produced from already discovered resources to vary significantly in the near future as a result of the merger.

2. Neither the proposed merger nor the Charter will alter the value of ANS in destination markets or the average transportation costs to move ANS to those markets. As a result, there should be no effect on projected royalty or production tax revenue. [2]

3. The value of oil and gas property and, thus, the revenue derived from the property tax, will be unaffected by who owns the assets that are being taxed.

As noted, the elements that most affect total revenue from oil and gas are production volume and production value, which are determined by the price of crude oil and the costs of getting it to market. Part II of this report deals with production volume issues, which were critical components of the negotiation of the Charter as well as our analysis of how the merger might affect the forecast. Part III focuses on the market value of ANS crude and the cost of transporting ANS to its market destination, two issues critical to forecasting the two largest revenue sources: production tax and royalties.

Finally, in Part IV, the revenue sources and the implications of the merger on them are discussed in more detail.

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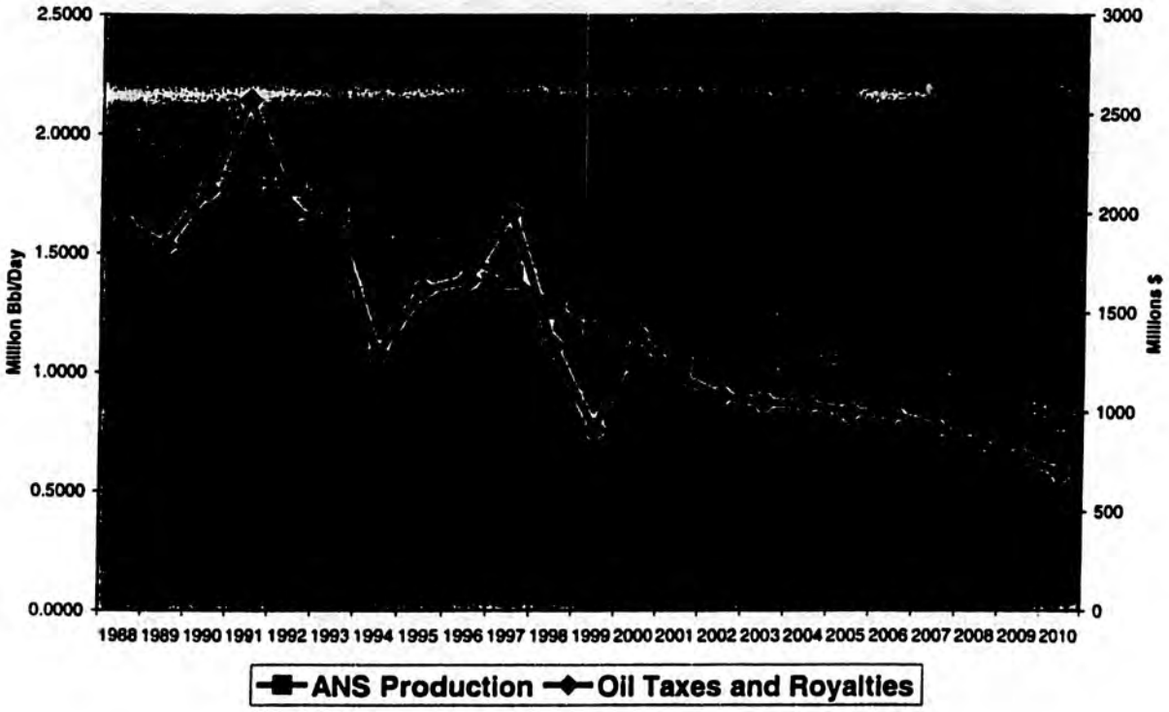
[2] If, however, the FTC were to condition approval of the proposed merger on terms that would shift the value of our oil resources from the upstream production sector downstream to West Coast refineries, the state's royalty and production tax revenue would certainly be reduced. This possibility is not reflected in the department's forecast.

II. PRODUCTION VOLUME

Over the long term, increases in state revenues from the oil industry will only result from exploration efforts that find and produce barrels to replace the declining production of the Prudhoe Bay and Kuparuk fields. Chart 1 below compares the total annual general fund revenue from oil (the right-hand axis) to the total production of ANS (left-hand axis). From 1988 through 1999, actuals are shown, and, although at times revenue increased despite a fall in production, the underlying trend is clear. The years 2000 through 2010 are presented as a forecast, and again, the relationship between revenue and volume is clear.

Oil Production and Oil Taxes and Royalties



The department's biannual revenue forecasts are based on fields currently producing or already discovered and about to come on line. These forecasts make no allowance for the role of future discoveries. As our consulting engineer points out, while production from satellite fields can be brought online within two years, production from new stand-alone fields is at best five to six years away. Traditionally it takes about a decade to bring a new discovery on line, although the industry is trying to cut that time significantly. However, an exploration season, a delineation season, and three years to design, fabricate, and install production

facilities add up to five years as the shortest possible time frame.[3] All the production in the department's forecast comes from projects on line or in the works, and analysts believe nothing else is likely inside the next five years. In fact, with one minor exception, the long-range forecast does not include any new production from fields coming on line after 2005.[4]

In the long run, although the department believes that a merger undertaken with the divestitures required by the Charter will lead to more barrels being produced than a merger without divestitures, analysts cannot reliably predict how many barrels the new competition will produce. In any case, because the department limits its forecast to discovered barrels, the merger's potential effect on future exploration and development is not relevant.

There is general agreement that North Slope producers will engage in the activities required for new production only if they can keep costs in line with worldwide cost structures. Controlling costs is critical to long-term production. The analytic question posed by the merger was how the state ought to act to best facilitate industry efforts to control costs.

Basic economic theory tells us that a monopoly is efficient *in the short run* because it eliminates needless duplication and overhead and cuts down per-unit fixed costs. However, that same theory holds that *over the long run*, monopolies tend to become inefficient because they are sheltered from competition. With no competition, the monopoly's costs grow unchecked because they can be passed on to consumers. Because there is no competitive challenge, the monopoly does not need to innovate.

Analogous reasoning applies to the North Slope.[5] Over the short term, a North Slope dominated by BP might generate lower costs, higher netbacks, and higher production. However, the state's negotiators concluded the best long-term guarantee for innovation, cost-cutting, and resulting future additional production was diversity and competition from other North Slope players. This is the long-term path the state opted for in the Charter and the rationale behind the required divestitures.

BP argued that it should not be required to divest, because the merger could create such large cost savings. BP claimed that, if the state did not interfere with the merger, it could slash unnecessarily duplicated North Slope costs and afford to reinvest $5 billion in Alaska over the next five years, increasing production over that same period by 150,000 barrels per day. Those short-term cost savings, BP assured state negotiators, would translate directly into reinvestment and more barrels.

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3 Furthermore the 'invest as you learn' approach to developing new fields suggests that it is unlikely there will be simultaneous parallel development at several separate fields by the same firm.

4 The production forecast includes some already discovered offshore production, which the department assumes will use existing production facilities coming on line in 2008 at roughly 15,000 barrels per day.

5 Analogous reasoning does <u>not</u> apply downstream. In the market where ANS is sold it constitutes less than half of the crude. Furthermore, that market is accessible by every major water- borne crude stream. The department does not believe BP is a monopolist supplier of crude. Again, the Department's forecast does not include the possibility that the FTC <u>will</u> conclude that BP is a monopolist.

The state did not accept BP's argument and insisted on divestiture, thus inviting new operators to the North Slope. As a result, it appears that North Slope production will still be saddled with the costs of two Anchorage office buildings, two legal departments, two marketing departments, and the like. It will not be as efficient, in the short run, as a combined BP/Arco that was not required to divest any holdings. Nevertheless, in the long run, these extra costs, required by reason of multiple North Slope operators, should be offset by the other efficiencies that competition brings.

When considering cost-control and its subsequent effect on production volume, it is important to focus on the role played by the operator rather than focusing on ownership percentages. The operator is hired by the owner or owners to run the field. The main responsibility for cost-control, innovation, and introducing efficiencies rests with the operator. An owner looks over the operator's shoulder and can sometimes even veto ideas it does not like. However, the operator runs the field. Prior to the merger, BP as operator was responsible for 37 percent of the production (Greater Endicott, Greater Milne Point, and half of Prudhoe Bay) while Arco, as operator, was responsible for 63 percent of the production (Greater Kuparuk, Greater Point McIntyre and the other half of Prudhoe Bay). After the changes in operatorship anticipated by the Charter take effect, BP, as operator, will be responsible for 72 percent of the production, and the new operators the other 28 percent. In short, the Charter largely perpetuates today's operating pattern, where one operator is responsible for about two-thirds of the production. To the extent that the percent of operations controlled by a single operator matters for cost-control, there will be little change from the current situation resulting from merger and divestiture.

On the other hand, Prudhoe Bay is one of the few places in the world with responsibilities split between two operators: Arco on the East Side and BP on the West Side. In the early eighties, each side produced more than 700,000 barrels per day. Industry analysts believe that it no longer makes sense to have two operators at Prudhoe now that its total production has fallen below 600,000 barrels per day. Many believe two operators at Prudhoe Bay simply add unnecessary costs to the operations there. For this reason, the Charter would not dilute BP's plan for a single Prudhoe operator and hoped-for cost savings at Prudhoe Bay.

II. CALCULATING ANS WELLHEAD VALUE FOR ROYALTY AND PRODUCTION TAXES

Royalties and production taxes have many differences that will be explored in Part IV below, but they have an essential similarity in that for both the amount due to the state is a function of wellhead value, calculated as a "netback." The starting point for the netback is the destination market, where the market value of the crude oil (ANS) is established. Then the value is "netted back" – by subtracting out the costs of 1) tanker transportation from Valdez to the destination market, 2) transportation of the oil through TAPS from the North Slope to Valdez, and 3) if necessary, getting the crude oil from the farther reaches of the North Slope to the inlet of TAPS. What is left over is "wellhead value," the basis for royalties and production taxes due the State. The higher the wellhead value, the more oil revenue the state collects.

The elements that determine the wellhead value, and how they may be affected by the proposed merger, are discussed below.

A. Market Value

Alaska's fiscal system is designed to get a fair market value for the state's oil in both the royalty and production tax contexts. For the past decade, fair market value for deliveries to the US West Coast has been measured by the ANS spot price.[6]

The bulk of the ANS is delivered to the U.S. West Coast. As a rule, Arco and Exxon have delivered most of their ANS to their own refineries. Producers with smaller shares of production generally sell their crude to one of the larger producers up-stream. As a result, BP has been the main merchant marketer of oil. Since the "spot price"[7] reflects deals reported in the marketplace, BP's market performance is a major driver of that price. As a seller, BP tries to achieve the highest price possible. BP's interests have been aligned with those of the state in this regard, as both benefit from high ANS crude prices.

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[6] In the administration of the production tax, Prevailing Value is defined by the ANS spot price. Two of the three major royalty settlement agreements use the ANS spot price as a destination value, provided it falls within a range defined by a basket of six crudes. The final major royalty settlement agreement defines the destination value using this same basket – in which the ANS spot price is weighted at 18%.

[7] The spot price is a daily assessment of deals being done in the market. At least four different organizations, Reuters, Telerate, Platts and OPIS give daily ANS quotes. These quotes have become accepted by both buyers and sellers in the industry, to the point where deals will be concluded based on a yet to be published set of ANS spot prices.

A special problem arises when the market becomes thin, and very few deals are made or reported. At the moment, most of the spot sales are made by BP. But after the merger, BP will have fewer, not more barrels for sale. Why? What is now Arco's production will continue to flow to what are now Arco's refiners. But BP must divest 175,000 bbls a day that it currently sells (or would sell, since this figure includes not-yet producing Alpine field). Of course, BP moves a lot of crude in long term contracts – sales that show up in the spot market at most once, when the deal is struck. If the party acquiring the 175,000 bbls is a merchant marketer, then the spot market may continue to be viable. But if not, or if BP commits most of its oil in long term contracts, or meets other FTC demands that get it out of the crude market, the market may become too thin, and the reported spot price unreliable.

The state and the FTC agree that BP has a great deal of influence on the spot price of ANS. But far from being concerned that BP will use its power to manipulate the spot price of the ANS upward, the state needs to be more concerned that the merger will give BP an incentive to manipulate the spot price of ANS downward.[8] Analysts label this BP's "perverse incentive."[9]

If state officials become concerned that the spot price is no longer the appropriate marker, the state has the ability to change the applicable regulations and reopen royalty settlement agreements, to protect value. In forecasting future revenues, the department will always use fair market value.

B. Netback Costs

As noted, the costs of transporting crude oil are offset against the ANS market value to determine the netback value upon which taxes and royalties are based. These costs include both marine and pipeline transportation. Other costs, including overhead and production operations on the North Slope, are generally excluded from royalty and severance tax netbacks or included on a formulaic basis. Thus, increases or decreases in transportation costs will affect state revenue, while increases or decreases in other types of costs will not have an effect on revenue under current formulas and agreements. Each of these types of costs and the post-merger factors that may affect them will be discussed in more detail below. The department's forecast is based on an assumption that **no significant changes will occur in these costs as a result of the merger under the conditions of the Charter for Development. As a result, there will be no effect on the netback value of Alaska oil or the revenue stream from that oil.**

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[8] BP can actually increase its total take from ANS by using a low spot price to lower the severance taxes and royalties due to the State. With the merger, BP acquires a large number of internally refined barrels. Even though those barrels are never sold, the taxes and royalties BP owes the State for those barrels are still calculated using the ANS spot price. As the spot price increases, BP gets more revenue from the barrels that it actually sells, but it has higher tax and royalty costs on all of its barrels. There comes a point when the added tax and royalty bill from high spot prices on the internally refined barrels overwhelms the cash effect of moving BP's sales barrels at a higher sales price. At that point BP's incentive changes from raising spot prices to lowering spot prices and the interests of the state and BP are no longer aligned.

[9] Ironically, some of the solutions being explored by the FTC and BP could easily establish a situation where BP would have this perverse incentive. The FTC is trying to reduce BP's market power by reducing the number of barrels in sells in the spot market even as the state seeks to have BP maximize the number of barrels it sells in the spot market. Since BP makes money from all aspects of the oil business, it may decide that giving up money as a merchant marketer is a price worth paying for the merger to go through. But the state sees no such trade-off.

1. Netback Costs--Tankers

ANS moves from Valdez to the West Coast on a fleet of "Jones Act" tankers, i.e., tankers built, owned and operated by U.S. companies. The market for these tankers is very restricted, and every Jones Act tanker appropriate for transporting crude oil and larger than 55,000 DWT is already in the ANS trade. Arco owns a fleet of five tankers. BP, as a "foreign-owned:" corporation, cannot own Jones Act vessels and leases eleven ships from American owners.

It is generally accepted, and confirmed here, that Arco has lower transportation costs to the West Coast than BP. Some observers have predicted that the total post-merger transportation costs of the combined companies will increase, thus leading to a decrease in revenue to the state. However, despite the merger, we believe that essentially the same Jones Act fleet will be hauling ANS. The merged entity should have transportation costs to the West Coast very close to the average of the two if it continues to use the vessels currently in the ANS trade. As an example, suppose there were two companies, each with a tanker of equal size, and it cost $1 per barrel to ship on one tanker and $2.00 per barrel to ship on the other. If the two companies merged, the average shipping cost would be $1.50. Thus in the calculation of costs, a merger would not affect the actual average netback or marine transportation costs. If a new player required by divestiture acquires some of the vessels, again, the overall average fleet cost will be the same – it will just be divided up differently between royalty and tax payers. In other words, there should be no net effect on the transportation deduction. BP argues that there will be a synergy from combining the fleets, and that post-merger, average costs may be lower. However, most of the savings are likely to be in overhead, which, as discussed below, may have very little effect on the netback.

Why are Arco's marine costs lower? Mostly because it hauls its crude to its own refineries in Puget Sound and Los Angeles and it has been able to optimize the design of its fleet with those two ports in mind. BP, on the other hand, is a seller of ANS, and it must make deliveries wherever a customer has a refinery. BP has a wider range of ports it visits, and it has several customers in the San Francisco area. In general, Puget Sound is the least expensive destination to reach, Los Angeles the next, and, finally, the San Francisco Bay area, where lightering – reloading the crude onto smaller vessels -- is required. In addition, frequently BP must discharge a portion of a load in one port and the balance of the load in another port. Having to make multi-port discharges adds significantly to the average per barrel cost. Again, the department assumes that if the distribution of destinations stays roughly the same after the merger, then average costs should remain unchanged.

Looking not at West Coast costs, but at the overall netback illustrates another reason for Arco's lower average shipping cost. BP ships ANS to the Far East. BP has pledged to use Jones Act vessels for these shipments, which means for them, shipping to the Far East is relatively expensive.[10] (That is not to suggest that if the Far East placements were discontinued and that crude went to the West Coast that BP's average netback would increase; in fact, it would more likely decrease due to downward pressures on prices that the extra crude would create.) We project that the volume of Far East placements will not change over the short run as a result of the merger.

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[10] While the law allowing export called for American-flagged and American-crewed ships, it did not require American-built vessels.

Analysts anticipate that the current fleet will be replaced by new double-hulled tankers earlier than the schedule set by the Oil Pollution Act of 1990 (OPA 90). It is perhaps worth mentioning that these tankers are more expensive than the old 1970's era single-hulled tankers they are replacing. Many tankers must be replaced in 2006-2008. The department's model, used to help shape the state's negotiations with BP, starts replacing older tankers earlier, rather than assuming that a large number of different shipyards would build all the required tankers in a short time. Thus, the model parallels BP's promise in the Charter to replace older tankers one year sooner than required by OPA 90.

2. *Netback Costs--Overhead*

The state has fought for decades over what constitutes allowable actual transportation costs. In general, it has been successful in limiting the effect of overhead and indirect costs on royalty and severance tax netbacks. As mentioned, these are precisely the kinds of costs that BP intends to cut to make the new operation more efficient. When the costs that flow into the royalty or severance tax netback are cut, the netback goes up. However, the converse is also true – when costs are cut that did not flow into the netback, the netback does not increase. In fact, there may even be an incentive for cost cutters to cut non-allowable costs because they are fully aware that BP gets the entire benefit of those cuts. When it cuts a cost that formed part of the royalty or tax netback, on the other hand, BP will have to share those cost savings with the state.

3. *Netback Costs--Upstream*

Similarly, the costs of the production operation on the North Slope do not, for the most part, affect royalties or severance taxes. Except for common carrier pipelines, costs upstream of TAPS are either deducted on a formulaic basis or not permitted to reduce royalty or tax value at all.[11]

C. Pipeline Transportation - Trans-Alaska Pipeline (TAPS)

As discussed earlier, state revenue from the oil industry comes in four types. Each type is structured differently and focuses on a different aspect of the industry, which provides the state with a balance in its revenue stream and a "hedge" against a major decline in any one aspect of the industry. For example, the claim is often made that a large reduction in the TAPS tariff would lead to **increased** severance tax and royalty revenues for the state because the netback adjustment to the market price would be less. This is only half the picture. If there are "obscene" profits in TAPS, the income tax and the property tax (which uses the present value of all future net income (not revenue) to arrive at an assessed value for TAPS) each take their piece of those profits. A reduction in the TAPS tariff would therefore lead to a partially offsetting **decrease** in income and property tax revenues for public finances. In fact, **almost half of the increase in production tax and royalty would be offset by a decrease in income and property tax.** Furthermore, because of the way the property tax is divided

[11] If the State determines that those upstream costs have changed, i.e, if post-merger BP is able to introduce cost savings in production, it may want to try to revisit some of the formulas.

between the state and municipalities, about one third of the net increase in state revenue would come from the pockets of the pipeline municipalities rather than from the industry. This was one reason the state's negotiators did not require a reduction in the tariff.

III. REVENUE EFFECTS

As noted, the State of Alaska receives revenue from the oil industry in four ways: through the property tax, royalties from production on state land, the production or severance tax, and the income tax on oil and gas producers and pipelines. Before the discussion of each of these, however, two other factors are worth mentioning.

A. Additional Factors Affecting Revenue to the State of Alaska

1. State As a Stockholder

The state's most immediate exposure to the effects of the proposed merger is through ownership of BP Amoco and Arco stock, though this ownership played no role in the state's negotiating strategy. As of October 31, 1999, the State of Alaska, through both treasury-managed funds and the Permanent Fund, owned $100 million of BP stock. When BP shares fell by 9 percent from 57¾ to 52¼ in the first week of November, the state lost about $9 million. Over the following week BP's price rebounded by 14 percent, up to over 60, giving the state over $10 million in additional investment earnings. None of the other effects discussed below will happen nearly that fast. The State of Alaska should not forget that it is a financial investor as well as sovereign and landowner.

2. Industry Job's Impacts on State Revenue

Neither an increase nor a decrease in industry employment will affect state revenues because the state's fiscal system does not include a personal income tax[12] or sales tax. Therfore, increased (or decreased) personal income or even resulting changes in purchasing power associated with the level of employment in the oil industry have no effect on state revenues. Although there may be very large effects on Alaska's overall economic health, with ripples that move from the oil sector to affect all other private sectors of the economy, the state as revenue collector is often situated similarly to the corporations in the oil patch. In this context, jobs can be thought of as costs that take away from the bottom line, whether it is the corporation's profit or the state's revenue. In other words, however relevant employment levels may be to the overall economic health of Alaska's economy, they are not pertinent to the state's fiscal picture in the absence of a broad-based revenue source tied to personal income or consumption. In fact, the costs of providing governmental services generally increase with increased employment, while revenues do not.

B. Oil and Gas Property Tax (AS 43.56)

The department's revenue forecast does not anticipate any increases or decreases in revenue from the property tax in the near future. Under the provisions of AS 43.56, the state levies a 20 mill tax on all oil and gas property in Alaska. Municipalities can also levy their local mill rate against the same property, and the taxes paid to the municipalities become a credit against

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[12] The state also lacks a broad- based business income tax. In 1997 there were 70,525 business registered to do business in Alaska. Of those, 62,598 choose a corporate form (proprietorship, partnership, or S corporation) not subject to income tax in Alaska.

the state tax. In FY 1999, the state and municipalities collected $270 million[13] from oil and gas property taxes.

The amount of tax collected is independent of who owns the assets. If increased industry activity in a post-merger period results in increased assets in the state, the tax base will increase. If cost cutting means cutting back on assets in Alaska, the tax base will decrease. However, it may take years for either the decreasing or increasing scenario to play out.

The vast majority of the taxable property consists of production facilities on the North Slope. The next biggest piece of taxable property is TAPS. The Department of Revenue's regulations (15 AAC 56.100 (c)) call for 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" in determining the value of a pipeline. For over twenty years, the state has relied on the income model, which sets a value for the pipeline using the present value of "estimated future net income." Currently, TAPS' value is assessed at just over $3 billion, based on the income that the pipeline owners will receive under the TAPS Settlement Methodology (TSM), which will be in effect until 2008. The department believes the merger will have no direct quantifiable effect on property tax.

C. Royalties from Oil and Gas Production on State Land (AS 38.05)

The North Slope fields are on state land, and the state as landowner gets 12.5 percent (and in some instances more) of the oil produced in exchange for granting the companies the right to produce that oil. The state collected over $517 million in oil and gas royalties in FY 1999. [14] Royalties are determined by a contract between the landowner and the producer. The department does not anticipate a significant change in royalty returns to the state as a result of the merger. The merger should have little effect on either market behavior or the costs of transportation, the elements that determine the value on which royalties are calculated.

In the early 1990s Arco and BP each reached a separate resolution with the state about how they would calculate their royalties, including how allowable costs would be determined. These resolutions included different transportation allowances that resulted in Arco deducting a much lower transportation cost than BP. This has led some to conclude that applying BP's higher transportation rate will reduce royalties to the state in the post-merger period.

While there may be some reduction, fleet synergies may also lend to a reduction in costs and an increase in royalties. Both the Arco and the BP formulas were intended to approximate the respective company's actual costs to be deducted in the royalty netback. To the extent that either party to the respective settlement believed it did not, the state or the company could ask to renegotiate the formula. In December 1998, Arco exercised its right to reopen the royalty formula because of its view that its allowed transportation charges did not reflect its true costs. Also in 1998, the state requested a reopening of BP's destination value formula.

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13 Of this, $48.8 million was state revenue and the rest went to the municipalities.

14 Of this, $348 million was unrestricted revenue, while the rest was divided between the Constitutional Budget Reserve (CBRF), the Permanent Fund, and the School Fund.

Both those negotiations were suspended pending the resolution of the larger merger issue. Both reopener processes are subject to binding arbitration in the event that the parties are unable to reach agreement, and both incorporate retroactive revisions back to the time of the reopener. Thus, any comparison between Arco and BP wellhead values since 1999 is a comparison of interim figures, representing two ways of approximating royalty value, both of which will be retroactively revised -- and neither of which currently represents a meeting of the minds between industry and the state. Over the long term, state royalty cost deductions will be what the state and the industry can negotiate and, if those negotiations fail, whatever an arbitrator finds fair. In either case, they will closely track the company's or companies "actual costs."

E. Production (Severance) Tax (AS 43.55)

The state has imposed a tax on oil production in the State of Alaska. For most oil the rate is 15 percent of the 87.5 percent left over after the royalty has been withdrawn, times the Economic Limit Factor (ELF). The ELF currently averages about 80 percent, so the effective tax on all barrels is about 10 percent. The State raised $395 million in severance taxes from the oil industry in FY 1999.[15] Production taxes are essentially levied on the same netted-back wellhead value as royalties.

Based on preliminary evaluations, the acquisition should have no effect on production taxes. As long as the oil is delivered to the same market, and the assets used to ship it are the same, there will be little, if any, change.

F. Income Taxes on Oil and Gas Producers and Pipelines (AS 43.20.072)

The state has an income tax of 9.4 percent with special rules that apply only to companies that have pipelines or oil production in the State of Alaska. In FY 1999, the State realized $165 million in income tax from the petroleum industry.[16] This tax is the hardest to analyze, both for our forecast and in terms of merger-related effects. As a result, we did not modify our standard forecasting process in the Department of Revenue's fall forecast to account for the effects of the merger. The merger may reduce state revenue, or it may increase state revenue. The available information is insufficient to support a change from our standard procedure.

Alaska's oil income tax uses a modified apportionment system. To build a bottom-up forecast of income tax revenue, the department first needs to know or project the total unitary income: how much the BPs, Arcos, Exxons, Mobils, and Amocos of the world make worldwide.[17] This tells us how big the pie is. The larger and more diversified the business entity, the harder that projection becomes.

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15 Of this $371 million was unrestricted. The rest came from settled disputes and went into the CBRF.

16 Of this, $145 was unrestricted and the rest came from settled disputes and went into the CBRF.

17 No annual returns from recently merged companies have yet been filed. The BP Amoco combination was effective in 1999, and the first full returns covering that period have not yet been filed.

Then, for modified apportionment, a forecaster needs to know, or project, each of three apportionment factors: the firm's extraction (or production), sales, and assets, for Alaska alone and for the rest of the world. The three factors are then averaged to arrive at an apportionment factor, which tells us how big a slice of the pie is taxable as Alaska income. The unitary income is then multiplied by the apportionment factor, and the result is taxable Alaska income. Needless to say, any bottom-up prediction of revenue from this tax is difficult, especially with reference to the post-merger period.

There are other difficulties associated with predicting this source of revenue. The income tax is a tax on what is left over after subtracting expenses from revenues. The three mechanisms already discussed -- property taxes, production or severance taxes, and royalties -- are all deductible expenses. First-order changes in those revenues will create second-order effects in the eventual income tax revenues. In addition, huge swings in unitary income can result from events outside Alaska, or changes in either the federal tax code or the tax code of some other jurisdiction in which oil companies are doing business.

Department of Revenue analysts do not apply a bottom-up analysis in forecasting incomes, but use three different techniques. First, they look at past and current quarterly estimated payments and analyze carry-forwards and refunds due to figure out the amount of tax expected in the next year. Second, they run a regression model that uses production times price to give a general forecast of income tax, assuming that the relationship between those factors will be the same in the future as in the past. A merger of two large entities such as BP and Arco is the classic example of a situation in which a regression developed from separate entities is not likely to be appropriate for the merged entities. Finally, for the more distant years, analysts step down from current year figures. The roundness of the projections suggests the accuracy of the forecast. The best that can be done is to estimate the general level of tax.

Alaska's taxable income can increase because either there is a bigger slice of smaller pie, a bigger slice of a bigger pie, or a smaller slice of a bigger pie. Alaska taxable income can decrease because either there is a smaller piece of a bigger pie, a smaller piece of a smaller pie, or a larger piece of a smaller pie. Neither a bigger slice or a bigger pie automatically means more revenue.

Auditors from the Division of Income and Excise Audit have analyzed prior income tax returns for the five companies involved in the completed or proposed mergers. In each of several years, analysts combined older returns of companies that had proposed merging. They compared the tax that would have been due from the combined returns with the sum of the taxes shown on the individual returns. Some of the combined returns generated less income tax than the sum of the individual returns. Other times the combined returns generated more income tax than the returns showed individually. The net effect of all the combining activity was a decrease in tax compared to the returns filed individually. Specifically when the five returns of merging firms were considered individually and then combined into pertinent groups of two and three, resulting income taxes fell by an average of $20 million a year. That means the tax fell, not because unitary income fell, but because the State of Alaska took a smaller slice of the same sized pie. Although this may seem like a significant sum, it should not be considered a forecast of falling revenue. Combining companies is a very different proposition from combining the historical returns of separate companies. Companies merge to use the same assets to create more income. In a simplified world, more income would mean

more income tax. However, in the real world, total tax can fall even when net income stays the same. Because the merger will rearrange how assets, production, and sales are divided between Alaska and the rest of the world, we cannot predict how much of that income would be attributable to Alaska, and thus taxable by Alaska.

On the other hand, **even though much of the potential merger-related cost savings will not result in increased wellhead values for the State of Alaska, it will result in increased unitary income.** In fact, the whole billion dollars that BP hopes to achieve in cost-savings from its acquisition of Arco would feed into unitary income. However, if those cost savings resulted in a larger decrease in Alaskan assets than in worldwide assets, Alaska's return through the income tax would be smaller.

In conclusion, analysis of past returns suggests a merger might result in lower income tax revenues. The common-sense notion that the purpose of the merger is to increase income suggests that a merger might increase taxable income. These two effects are laid over the inherent difficulties associated with projecting modified apportionment income. The result is that we believe our current income tax projection is the best estimate of revenue, whether the merger occurs or not.

V. SUMMARY

Our analysis demonstrates that the state's revenues are determined not so much by who owns the barrels, but how many of them are produced. Consequently, for the short to medium term, we have tentatively projected no material change in state oil revenue resulting from the merger. I say tentatively because the FTC certainly might compel changes in the marketplace as a consequence of the merger that would reduce state revenue.

The goal of the Charter for Development of the Alaskan North Slope was to keep North Slope competition alive in the long term and create replacement barrels for the fields that drive our current production. It will be many years before our forecasts will begin to reflect whether that attempt was successful or not.