SCOMM

148:10

# ALASKA STATE LEGISLATURE


## HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Representative Kurt Olson, Chair
State Capitol, Room 408
Juneau, AK 99801-1182
Phone 907-465-2693 Fax 907-465-3835

Official Business


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**Friday, October 19, 2007**
**1:30 pm – 6 pm**
**Room 519**

# AGENDA

**HB 2001**
**Oil and Gas Tax Amendments**

Requester Presentation by: Governor's Production Tax Team

Patrick Galvin, Commissioner Dept. of Revenue
Marcia Davis, Deputy Commissioner Dept. of Revenue
Jon Iversen, Dir. Tax Div., Dept of Revenue
Bob George, Gaffney, Cline & Associates
Rich Ruggiero, Gaffney, Cline & Associates


Committee Staff: Konrad Jackson (907) 465-4530 phone (907) 465-3835 fax

# ALASKA STATE LEGISLATURE

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Representative Kurt Olson, Chair
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Representative Ralph Samuels
Representative Nancy Dahlstrom
Representative Scott Kawasaki

Representative Jay Ramras
Representative Mike Doogan

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HB 2001 Bill Packet Information
October 19, 2007

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Enclosed Documents:

- HB 2001 "Oil & Gas Tax Amendments" bill - ver. 25-GH0014\A
- Fiscal Notes
    1. Administration
    2. Dept. of Revenue
    3. Dept. of Natural Resources
- Bullock Sectional - HB 2001
- Dept. of Revenue – Sectional Analysis
- Porter-Dickinson Sectional – referencing "Work Draft" version
- Dickinson – Detail Comparison Matrix– referencing "Work Draft" version
- Dickinson – Summary Comparison Matrix– referencing "Work Draft" version
- Dickinson Revenue Estimate - referencing "Work Draft" version
- Leg Finance Review – referencing "Work Draft" version
- Letter from Governor to Representative Doogan
- Public comments
- Statutes AS 43.55

# FISCAL NOTE

**STATE OF ALASKA**
**2008 LEGISLATIVE SESSION**

Fiscal Note Number: 1
Bill Version: HB 2001
(H) Publish Date: 10/18/07

Identifier (file name): LL 08-0014-DOA-DAS-10-17-07
Title: An Act relating to the production tax on oil and gas...
Sponsor: Governor
Requester:

Dept. Affected: Administration
RDU: Centralized Admin. Services
Component: Office of the Commissioner
Component Number: 45

**Expenditures/Revenues** (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

| | Appropriation Required | Information | | | | | |
|---|---|---|---|---|---|---|---|
| **OPERATING EXPENDITURES** | **FY 2009** | **FY 2009** | **FY 2010** | **FY 2011** | **FY 2012** | **FY 2013** | **FY 2014** |
| Personal Services | | | | | | | |
| Travel | | | | | | | |
| Contractual | | | | | | | |
| Supplies | | | | | | | |
| Equipment | | | | | | | |
| Land & Structures | | | | | | | |
| Grants & Claims | | | | | | | |
| Miscellaneous | | | | | | | |
| **TOTAL OPERATING** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| **CAPITAL EXPENDITURES** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |
| **CHANGE IN REVENUES ( )** | | | | | | | |

**FUND SOURCE** (Thousands of Dollars)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1002 Federal Receipts | | | | | | | |
| 1003 GF Match | | | | | | | |
| 1004 GF | | | | | | | |
| 1005 GF/Program Receipts | | | | | | | |
| 1037 GF/Mental Health | | | | | | | |
| Other Interagency Receipts | | | | | | | |
| **TOTAL** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |

**Estimate of any current year (FY2008) cost:**

**POSITIONS**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Full-time | | | | | | | |
| Part-time | | | | | | | |
| Temporary | | | | | | | |

**ANALYSIS:** *(Attach a separate page if necessary)*

This legislation has no fiscal impact on the Department of Administration.

Prepared by: Eric Swanson — Phone 465-5655
Division: Administrative Services — Date/Time
Approved by: Annette Kreitzer — Date Oct. 12, 2007
Commissioner

(Revised 10/05/2008 OMB)

# FISCAL NOTE

**STATE OF ALASKA**
**2008 LEGISLATIVE SESSION**

Fiscal Note Number: 3
Bill Version: HB 2001
(H) Publish Date: 10/18/07

Identifier (file name): LL 08-0014-DOR-TAX-10-17-07
Title: An Act relating to the production tax on oil and gas..

Dept. Affected: Revenue 04
RDU: Taxation and Treasury
Component: Tax Division

Sponsor: Governor
Requester:

Component Number: 2476

**Expenditures/Revenues** (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

| | Appropriation Required | Information | | | | | |
|---|---|---|---|---|---|---|---|
| **OPERATING EXPENDITURES** | **FY 2009** | **FY 2009** | **FY 2010** | **FY 2011** | **FY 2012** | **FY 2013** | **FY 2014** |
| Personal Services | 1,215.7 | 1,215.7 | 1,215.7 | 1,215.7 | 1,215.7 | 1,215.7 | 1,215.7 |
| Travel | | | | | | | |
| Contractual | 1,018.4 | 1,018.4 | 1,018.4 | 511.8 | 5.2 | 5.2 | 5.2 |
| Supplies | | | | | | | |
| Equipment | | | | | | | |
| Land & Structures | | | | | | | |
| Grants & Claims | | | | | | | |
| Miscellaneous | | | | | | | |
| **TOTAL OPERATING** | **2,234.1** | **2,234.1** | **2,234.1** | **1,727.5** | **1,220.9** | **1,220.9** | **1,220.9** |
| **CAPITAL EXPENDITURES** | | | | | | | |
| **CHANGE IN REVENUES ( )** | | **675,000.0** | **603,000.0** | **589,000.0** | **624,000.0** | **597,000.0** | **416,000.0** |

**FUND SOURCE** (Thousands of Dollars)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1002 Federal Receipts | | | | | | | |
| 1003 GF Match | | | | | | | |
| 1004 GF | 2,234.1 | 2,234.1 | 2,234.1 | 1,727.5 | 1,220.9 | 1,220.9 | 645.9 |
| 1005 GF/Program Receipts | | | | | | | |
| 1037 GF/Mental Health | | | | | | | |
| Other Interagency Receipts | | | | | | | |
| **TOTAL** | **2,234.1** | **2,234.1** | **2,234.1** | **1,727.5** | **1,220.9** | **1,220.9** | **645.9** |

**Estimate of any current year (FY2008) cost:** 3,409.2

**POSITIONS**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Full-time | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Part-time | | | | | | | |
| Temporary | | | | | | | |

**ANALYSIS:** *(Attach a separate page if necessary)*

This bill makes significant changes to the state's current petroleum profits tax. The tax proposal, also known as the Clear and Equitable Share (ACES) plan, like the current tax system, taxes the net value of petroleum resources. The ACES proposal makes the following changes to the tax system: raises the tax rate to 25% on net profits of oil and gas production subject to a 10% floor on legacy fields; adjusts the progressive tax feature to trigger at $30 net value (annual) and rise at two-tenths of a percent per dollar; eliminates the transitional investment expenditures "TIE" credits; requires that capital costs be taken as credits over two years, rather than immediately; addresses the "corrosion" expense issue; excludes dismantlement, removal & restoration (DR&R) costs from allowable expenditures; expands exploration incentive credit program to cover two field seasons; requires taxpayers to provide cost projections to allow the state to better forecast state revenues and pursue changes in reported costs; authorizes public reporting of some cost data; authorizes a short-term audit program; and designates an exempt class of oil and gas auditors.

Prepared by: Cherie Nienhuis, Roger Marks, Johanna Bales
Division: Tax Division
Phone: 269-6628
Date/Time: 10/17/07 12:00 AM

Approved by: Jerry Burnett
Department of Revenue
Date: 10/17/2007

(Revised 10/05/2006 OMB)

**FISCAL NOTE #3**

**STATE OF ALASKA**
**2008 LEGISLATIVE SESSION**

**BILL NO.** HB 2001

**ANALYSIS CONTINUATION**

The tax proposal would also authorize a fund to be established for the purpose of purchasing tax credit certificates. The func would receive 10% - 15% of total production tax revenues annually (roughly $150 million to $300 million); up to $250 million of fund revenues would be paid to purchase credits in any given year.

Certain lease expenditure allowance provisions are retroactive to April 1, 2006; the other provisions of the tax proposal become effective January 1, 2008.

**Personal Services:** The department will reclassify the existing 5 vacant auditor positions, and create 4 to 5 senior level auditor positions with extensive industry oil and gas auditing experience. These positions will be classified as the Department's most senior level auditor positions and will have salaries that are consistent with market comparables and will be beyond the current salary levels allowed under the existing Oil and Gas Revenue Auditor (OGRA) pay classification system. In addition, the department expects that it will need one additional Programmer Analyst V position to maintain and manage the new oil and gas production tax database system at a cost of $115,700 annually. The existing oil and gas specialist, oil and gas revenue auditors, and their immediate supervisor will be offered the opportunity to opt into an exempt status with individual salaries established commensurate with experience and skill level, and consistent with market comparables.

The need for exempt status is based upon the difficulties the department has recruiting experienced auditors to administer the tax. The current pay range for an Oil and Gas Revenue Auditor is on the low range of the pay range for roughly similar jobs. The department estimates the new exempt positions and the potential salary increases associated with the change of existing staff to exempt status, will cost the state approximately $1,100,000 annually.

**Contractual:** Contractual expenditures include $1,013,200 annually to contract for audit assistance. This estimate is based on 3 auditors, working 40 hours per week each, for 4 years starting in January 2008 at an average rate of $100 per hour, plus estimated transportation and lodging costs, and additional costs for training auditors. The need for such assistance is based upon the department's substantial difficulty in recruiting enough auditors to administer the oil and gas production tax. The department only anticipates the need for contract audit assistance for 4 years while the department recruits and trains auditors for positions that are currently vacant. The contract auditors would work in conjunction with department auditors during this time to maximize department resources and help train department auditors. The department will also need an additional $5,200 each year in contractual costs associated with the new Analyst Programmer V position.

**Current FY2008 costs:** The department expects it will incur costs beginning January 2008 to immediately implement the new production tax structure. Those costs include: **Contractual** - $2,620,800 capital funding to fund the scoping and development of an oil and gas production tax database system (including associated hardware) and $506,600 to contract for audit assistance (as described above). The new database system will permit accurate and efficient management of information submitted by taxpayers to facilitate auditing and forecasting of revenues, and timely and accurate reports for internal and public uses. The proposed system will accommodate the migration of ELF-based data and continue to collect supplemental data from producers on volumes, wells and production. The system will include income-based data, including tracking credits, required under PPT and upon which the ACES tax structure is based. The system will also integrate into the division's accounting systems. **Personal Services** - $218,000 from the period January 1, 2008 through June 30, 2008 due to creating an exempt class of oil and gas revenue auditors and increasing pay to more closely reflect what the market in Alaska pays for roughly similar positions. In addition, we will recruit for the Analyst Programmer V and bring that person on board to participate in the database scoping meetings. We estimate FY 2008 costs for this position to be approximately $57,800. **Supplies** - $6,000 for a computer and software for the new analyst progammer V position.

See page 3 for projected revenue estimates.

STATE OF ALASKA
2008 LEGISLATIVE SESSION

BILL NO. HB 2001

ANALYSIS CONTINUATION

# Estimated Production Tax Revenues, PPT and ACES, at Various Prices (in $millions)

***Fall 2007 DOR Official Forecast Prices***

| Fiscal Year | ANS WC $ per barrel (in REAL dollars) | ANS WC $ per barrel (in NOMINAL dollars) | Status Quo - PPT | ACES | Increase or (Decrease) from PPT |
|---|---|---|---|---|---|
| 2008 | 71.65 | 71.65 | 1,915 | 2,330 | 415 |
| 2009 | 64.55 | 66.30 | 1,693 | 2,369 | 675 |
| 2010 | 60.05 | 63.40 | 1,531 | 2,134 | 603 |
| 2011 | 59.70 | 64.75 | 1,670 | 2,258 | 589 |
| 2012 | 59.55 | 66.35 | 1,746 | 2,370 | 624 |
| 2013 | 58.90 | 67.45 | 1,647 | 2,244 | 597 |
| 2014 | 58.25 | 68.55 | 1,642 | 2,058 | 416 |

DOR Forecast nominal prices rounded to the nearest $0.05

***$60 per barrel in REAL dollars***

| Fiscal Year | ANS WC $ per barrel (in REAL dollars) | ANS WC $ per barrel (in NOMINAL dollars) | Status Quo - PPT | ACES | Increase or (Decrease) from PPT |
|---|---|---|---|---|---|
| 2008 | 60.00 | 60.00 | 1,051 | 1,421 | 371 |
| 2009 | 60.00 | 61.65 | 1,435 | 1,977 | 542 |
| 2010 | 60.00 | 63.35 | 1,562 | 2,170 | 608 |
| 2011 | 60.00 | 65.09 | 1,695 | 2,291 | 596 |
| 2012 | 60.00 | 66.88 | 1,783 | 2,414 | 631 |
| 2013 | 60.00 | 68.72 | 1,733 | 2,347 | 614 |
| 2014 | 60.00 | 70.61 | 1,776 | 2,218 | 442 |

***$80 per barrel in REAL dollars***

| Fiscal Year | ANS WC $ per barrel (in REAL dollars) | ANS WC $ per barrel (in NOMINAL dollars) | Status Quo - PPT | ACES | Increase or (Decrease) from PPT |
|---|---|---|---|---|---|
| 2008 | 80.00 | 80.00 | 2,650 | 3,089 | 438 |
| 2009 | 80.00 | 82.20 | 3,031 | 3,717 | 686 |
| 2010 | 80.00 | 84.46 | 3,266 | 3,988 | 722 |
| 2011 | 80.00 | 86.78 | 3,481 | 4,189 | 708 |
| 2012 | 80.00 | 89.17 | 3,668 | 4,404 | 736 |
| 2013 | 80.00 | 91.62 | 3,619 | 4,327 | 708 |
| 2014 | 80.00 | 94.14 | 3,690 | 4,204 | 514 |

# FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 2
Bill Version: HB 2001
(H) Publish Date: 10/18/07

Identifier (file name): #773-08-0014-DNR-10-17-07
Title ACES

Dept. Affected: Natural Resources
RDU Resource Development
Component Oil and Gas Development

Sponsor Rules Committee
Requester Governor

Component Number 439

**Expenditures/Revenues** (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

| | Appropriation Required | Information | | | | | |
|---|---|---|---|---|---|---|---|
| **OPERATING EXPENDITURES** | **FY 2009** | **FY 2009** | **FY 2010** | **FY 2011** | **FY 2012** | **FY 2013** | **FY 2014** |
| Personal Services | 303.5 | 0.0 | 303.5 | 303.5 | 303.5 | 303.5 | 303.5 |
| Travel | | | | | | | |
| Contractual | | | | | | | |
| Supplies | | | | | | | |
| Equipment | | | | | | | |
| Land & Structures | | | | | | | |
| Grants & Claims | | | | | | | |
| Miscellaneous | | | | | | | |
| **TOTAL OPERATING** | **303.5** | **0.0** | **303.5** | **303.5** | **303.5** | **303.5** | **303.5** |
| **CAPITAL EXPENDITURES** | | | | | | | |
| **CHANGE IN REVENUES ( )** | | | | | | | |

**FUND SOURCE** (Thousands of Dollars)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1002 Federal Receipts | | | | | | | |
| 1003 GF Match | | | | | | | |
| 1004 GF | 303.5 | 0.0 | 303.5 | 303.5 | 303.5 | 303.5 | 303.5 |
| 1005 GF/Program Receipts | | | | | | | |
| 1037 GF/Mental Health | | | | | | | |
| Other Interagency Receipts | | | | | | | |
| **TOTAL** | **303.5** | **0.0** | **303.5** | **303.5** | **303.5** | **303.5** | **303.5** |

**Estimate of any current year (FY2008) cost:** 177.0

**POSITIONS**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Full-time | | | | | | | |
| Part-time | | | | | | | |
| Temporary | | | | | | | |

**ANALYSIS:** *(Attach a separate page if necessary)*

This bill would amend the oil and gas production tax under AS 43.55 to increase the base tax rate from 22.5% to 25% of net income and have the index-based progressive tax apply when net income per barrel exceeded $30 rather than the current $40 per barrel. In addition, this bill would change the minimum tax that currently applies to taxable income generated from North Slope fields, and which, for ANS West Coast prices above $25 per barrel, is now 4% of gross receipts at the lease boundary. The bill would increase the minimum tax rate to 10 percent gross, but apply this minimum tax only to large North Slope legacy units (Prudhoe Bay Unit and the Kuparuk River Unit). This minimum tax would also prevent these legacy field owners from using credits or deductions generated at these fields to lower their tax burden elsewhere when the minimum tax applies. In addition, the bill allows for tax credits on future work rather than previous work and expands the current exploration incentive credit program to include as many wells that can be drilled in two drilling seasons. It also restricts capital expense deductions to scheduled maintenance and would implement audit and information sharing provisions.

Prepared by: Kevin Banks, Acting Director — Phone 269-8800
Division Oil and Gas — Date/Time 10/17/2007
Approved by: Tom Irwin, Commissioner — Date 10/17/2007
Natural Resources

(Revised 10/05/2006 OMB)

**FISCAL NOTE #2**

**STATE OF ALASKA** **BILL NO.** HB 2001
**2008 LEGISLATIVE SESSION**

**ANALYSIS CONTINUATION**

**Indeterminate Positive: The royalty revenue impact to the State of ACES is indeterminate, but most likely positive. ACES improves the economics for new entrants or small Alaska producers, but decreases the attractiveness of investments in legacy fields.

Improvement in new entrant/small producer economics: ACES improves the economics of investing in Alaska for new entrants and small Alaska producers, an improvement that should lead to more investment and resulting royalty revenue. For new entrants and small producers, capital spent to find and develop oil or gas resources will generate a carried-forward annual loss credit of 25 percent rather than the current 20 percent AS 43.055.023(b).

Also, for new entrants and small Alaska producers, the transferable credits (the carried-forward annual loss credit and the 20 percent qualified expenditure credit (AS 43.55.023(a)) will be worth more under ACES. Small producers have indicated that they have been unable to sell their credits to larger tax payers. Under AS 43.55.028, ACES establishes an oil and gas tax credit fund that will help ensure these new and small producers will receive full value for these transferable credits.

Without the fund, the small producer or new entrant may have to carry-forward their credits until they have tax liability. By providing full value up-front for these credits, ACES improves the internal rate of return (IRR) by three to six percent at $40 per barrel ANS WC.

As a partial offset to this incentive, ACES increases the tax rate from 22.5 to 25.0 percent; has the progressive, index-based, rate kicking in at a lower level; and has credits being spread over two years rather than one. However, on balance, ACES will improve new project economics for new entrants and small Alaska producers.

Decrease in attractiveness of investments in legacy fields: ACES will decrease the attractiveness of investments made by larger, existing producers for three reasons: the higher tax rate, the elimination of the Transition Investment Expenditure (TIE) credit, and the 10 percent minimum tax on legacy fields.

First, ACES increases the tax rate from 22.5 percent to 25.0 percent. In addition, the progressive, index-based rate will start at a lower ($30) net value per barrel, but escalate at a lower rate (0.20 percent rather than 0.25 percent. Second, by eliminating the TIE credit, new capital spending by existing producers will no longer increase the ability of those producers to take the TIE credit by 10 percent of the capital invested. Third, at lower prices (prices far below where they are today) the minimum 10 percent gross tax applies, lowering or postponing the ability to take the capital expenditure credits. The floor also could eliminate the ability to use deductions generated by new spending to decrease tax liability. If the producers in these legacy fields (Prudhoe Bay Unit and Kuparuk River Unit) believe there is a good chance that prices will decline or costs will increase to the point where the floor applies, they might invest less in additional reserves in these legacy fields.

If these measures (the higher rate, the TIE credit elimination, and the 10 percent floor) cause less investment by existing producers to add reserves, the State will receive less in royalty.

Personal Services: Sections 10 and 67 would reclassify the current oil and gas auditors to exempt status employees. DO&G currently has seven oil and gas auditor positions. The total salary/benefit costs for these seven employees currently equals approximately $849,147. An increase to exempt status is estimated to cost up to an additional $303,500 in FY09. The FY08 amount of $177,000 covers an estimated 7-months at the higher rate.

# LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

**MEMORANDUM** October 19, 2007

**SUBJECT:** Sectional analysis for HB 2001 (Work Order No. 25-GH0014\A)

**TO:** Representative Kurt Olson
Attn: Konrad Jackson

**FROM:** Donald M. Bullock Jr.
Legislative Counsel

You have requested a sectional summary of the above-described bill.

As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. If you would like an interpretation of the bill as it may apply to a particular set of circumstances, please advise.

**Section 1.** States that the enactment of AS 43.55.075(b) in sec. 50 of the bill is to "confirm by clarification the long-standing interpretation of AS 43.05.260 by the [department]." (AS 43.05.260 relates to the limitation on assessment for taxes imposed by AS 43.)

**Section 2.** Amends AS 38.05.035(a) by adding a new paragraph that requires the director of the division of lands to furnish records, files, and other information related to the administration of AS 38.05.180 (oil and gas and gas only leasing) to the Department of Revenue for use in forecasting state revenue and the administration of AS 43.55 (oil and gas production tax and surcharges). In the case of information required to be held confidential under AS 38.05.035(a)(8), the Department of Revenue is to maintain the same level of confidentiality of the information as is required of the director of the division of lands.

**Section 3.** Amends AS 38.05.036(b) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 4.** Amends AS 38.05.036(f) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 5.** Amends AS 38.05.036(g) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 6.** Amends AS 38.05.123(f) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 7.** Amends AS 38.05.135(e) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 8.** Amends AS 38.05.180(j) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 9.** Amends AS 38.05.275(c) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 10.** Adds a new paragraph to AS 39.25.110 that makes oil and gas production tax auditors and their immediate supervisors in the Department of Revenue, and oil and gas royalty auditors and their immediate supervisors in the Department of Natural Resources exempt employees.

**Section 11.** Amends AS 41.09.010(d) by changing a cross-reference to a paragraph in AS 38.05.035(a); the change is required because the amendment of AS 38.05.035(a) in sec. 2 renumbered some paragraphs in the subsection and added a new paragraph.

**Section 12.** Amends AS 43.05.230(a) to include AS 43.55.890 (added by sec. 61 of the bill) as authority for divulging the amount of income or the particulars set out or disclosed in a report or return made under AS 43, notwithstanding the general prohibition in AS 43.05.230.

**Section 13.** Amends AS 43.05.230(h) by adding tax returns, reports, and documents filed under AS 43.55 and the Department of Revenue's determinations and workpapers under AS 43.55 and AS 43.65 to the information that the Department of Revenue is required to furnish to the Department of Natural Resources.

**Section 14.** Amends AS 43.05.260(a) to include AS 43.55.075 (added by sec. 50 of the bill) as an exception to the general three-year statute of limitation on assessment.

**Section 15.** Repeals and reenacts AS 43.55.011(e); the reenactment changes levy from a monthly to a calendar year basis; with certain exceptions, provides that the tax is equal to the production tax value of the taxable oil and gas multiplied by the percentage

determined under AS 43.55.011(g) (subsection (g) is repealed and reenacted by sec. 17 of the bill). Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 16.** Repeals and reenacts AS 43.55.011(f); the repeal and reenactment creates a new floor for the tax imposed on production from a unit or non-unitized reservoir from which 1,000,000,000 BTU equivalent barrels of oil or gas have been cumulatively produced before the start of the tax year and from which the average daily oil and gas production during the most recent calendar year exceeded 100,000 BTU equivalent barrels a day (so-called "legacy fields"); provides that tax credits may not be used to reduce the tax liability for these leases or properties below 10 percent of the total gross value at the point of production; provides that the effective tax rate under AS 43.55.011(e) may not be less than 10 percent of the total gross value at the point of production. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 17.** Repeals and reenacts AS 43.55.011(g); provides that the tax rate applicable to the tax value of oil and gas production is the sum of 25 percent plus the product of 0.20 percent (.002) times the price index determined under AS 43.55.011(h) (subsection (h) is amended in sec. 18 of the bill); limits the tax to a maximum rate of 50 percent. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 18.** Amends AS 43.55.011(h) to make the price index determined on a calendar year rather than a monthly basis, and to increase the nominal 25 percent tax when the average production tax value for all leases or properties in the state for the calendar year exceeds $30. Provides that the price index may not be less than zero.[1] Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 19.** Amends AS 43.55.011(j) (relating to Cook Inlet gas) to eliminate a reference to AS 43.55.011(g); the reference to AS 43.55.011(g) is no longer applicable with the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill and the repeal and reenactment of AS 43.55.011(g) in sec. 17 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 20.** Amends AS 43.55.011(k) (relating to Cook Inlet oil) to eliminate a reference to AS 43.55.011(g); the reference to AS 43.55.011(g) is no longer applicable with the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill and the repeal and

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[1] For example, if the average production tax value is $35 a BTU equivalent barrel, the tax rate is 26%. This is determined by starting with the 25% base rate in AS 43.55.011(g) and adding the product of 0.2% multiplied by 5, with "5" representing the difference between 30 and the average production tax value a BTU equivalent barrel.

reenactment of AS 43.55.011(g) in sec. 17 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 21.** Amends AS 43.55.011(m) by adding new limitations for excess tax credits associated with Cook Inlet gas production based on new subsections added to AS 43.55.160 by sec. 55 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 22.** Repeals and reenacts AS 43.55.020(a); provides the methods for determining the amount of monthly installment payments for the tax imposed on leases or properties outside of Cook Inlet excluding fields subject to tax under AS 43.55.011(f) (legacy fields), on leases or properties subject to AS 43.55.011(f), and on leases or properties in Cook Inlet; provides a limit on the amount of the installment payment for oil and gas produced in Cook Inlet; provides the method for determining the amount of the installment payment for the tax imposed on the production of taxable royalty oil and gas; and provides that any tax remaining due after the payment of the installment payments is due on March 31 of the year following the calendar year of production. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 23.** Amends AS 43.55.020(d) by changing a reference to the statute under which the tax is levied to conform with the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 24.** Amends AS 43.55.020(g) by changing references to paragraphs in AS 43.55.020(a) to conform to the repeal and reenactment of AS 43.55.020(a) in sec. 22 of the bill; clarifies the period during which interest accrues under 26 U.S.C. 6621 on the underpayment of an installment. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 25.** Amends AS 43.55.020(h) by changing references to paragraphs in AS 43.55.020(a) to conform to the repeal and reenactment of AS 43.55.020(a) in sec. 22 of the bill; clarifies the period during which interest accrues under 26 U.S.C. 6621 on the overpayment of an installment. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 26.** Amends AS 43.55.023(a) to require that no more than one-half of a credit for a qualified capital expenditure be applied in a single calendar year; amends the requirements for submitting information to the Department of Natural Resources as a

condition of taking the credit by referencing AS 43.55.025(f)(2) (AS 43.55.025(f)(2) is amended in sec. 39 of the bill); prohibits a credit for a qualified capital expenditure for exploration, development, or production on a lease or property subject to tax under AS 43.55.011(f) (legacy fields) from being applied against a tax for oil and gas production outside of those leases or properties. (The specific reporting requirements in the existing subsection are incorporated into the amended AS 43.55.025(f) in sec. 39 of the bill.) Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 27.** AS 43.55.023(b) is amended to increase the percentage of a carried-forward annual loss that may be taken as a tax credit from 20 to 25 percent; incorporates a limitation on a carried-forward annual loss under AS 43.55.160(h) (AS 43.55.160(h) is added in sec. 55 and is applicable to Cook Inlet); prohibits the carry-forward of adjusted lease expenditures to explore, develop, or produce oil or gas deposits within a unit or non-unitized reservoir subject to AS 43.55.011(f) (legacy fields). Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 28.** Amends AS 43.55.023(d) to limit the application of the subsection by making an exception for tax credits based on certain expenditures in legacy fields (AS 43.55.023(a)(3) in sec. 26 of the bill); references the ability to obtain a cash payment for tax credits under AS 43.55.028 (AS 43.55.028 is added in sec. 45 of the bill); doubles the period for the department to grant, deny, or grant a limited credit by changing the period for acting from 60 to 120 days; amends one of the three alternative starting points (the latest is used) to start the period for departmental action on the date a statement under AS 43.55.030(a) or (e) is filed (AS 43.55.030(a) is amended in sec. 46 of the bill and AS 43.55.030(e) is added in sec. 48 of the bill); requires the department to issue two credit certificates for the credits claimed with each certificate applicable to one-half of the credit amount; provides that the tax credit shown on one of the two credit certificates may be used immediately and prohibits the application of the tax credit on the other certificate before the calendar year following the calendar year in which the certificate is issued. Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 29.** Amends AS 43.55.023(e) to conform with the addition of new limitations on tax credits in AS 43.55.023(d) as amended in sec. 28 of the bill; makes a technical correction to recognize that the tax is "levied by" AS 43.55.011(e), as opposed to "due under" that subsection. Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and

gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 30.** Amends AS 43.55.023(g) by adding language to reflect the authority granted in AS 43.55.028 (AS 43.55.028 is added in sec. 45 of the bill) for the department to purchase tax credits authorized under AS 43.55.023. Under sec. 66 of the bill, this section applies to (1) transferable tax credit certificates under AS 43.55.023(d), and (2) transferable tax credit certificates under AS 43.55.023(d) in effect before January 1, 2008 for which a cash refund has not been issued under AS 43.25.023(f) before January 1, 2008. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 31.** Amends AS 43.55.023 by adding a new subsection that states that an entity that is exempt from tax under AS 43.55 may not apply for a transferable tax credit certificate. Under sec. 71 of the bill, this section is retroactive to April 1, 2006.

**Section 32.** Amends AS 43.55.024(a) to refer only to AS 43.55.011(e), the subsection under which the tax is levied following the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill, and the repeal and reenactment of AS 43.55.011(f) in sec. 16 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 33.** Amends AS 43.55.024(c) to refer only to AS 43.55.011(e), the subsection under which the tax is levied following the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill, and the repeal and reenactment of AS 43.55.011(f) in sec. 16 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 34.** Amends AS 43.55.024(e) to refer only to AS 43.55.011(e), the subsection under which the tax is levied following the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill, and the repeal and reenactment of AS 43.55.011(f) in sec. 16 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 35.** Amends AS 43.55.024(g) to refer only to AS 43.55.011(e), the subsection under which the tax is levied following the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill, and the repeal and reenactment of AS 43.55.011(f) in sec. 16 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 36.** Amends AS 43.55.025(a) to refer only to AS 43.55.011(e), the subsection under which the tax is levied following the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill, and the repeal and reenactment of AS 43.55.011(f) in sec. 16 of the bill; makes a technical correction to recognize that the tax is "levied by" AS 43.55.011(e), as opposed to "due under" that subsection; removes the requirement in AS 43.55.020(a)(2) that expenditures must be for work performed before July 1, 2007.

Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 37.** Amends AS 43.55.025(b) by changing the start date of the period in which exploration expenditures may qualify for the tax credit under AS 43.55.025(a) from July 1, 2003 to January 1, 2008; requires that the exploration well be completed or abandoned at the time the credit is claimed by an explorer under AS 43.55.05(f) (AS 43.55.025(f) is amended in sec. 39 of the bill); excludes costs from gross negligence or violation of health, safety, or environmental statutes or regulations from eligibility for the tax credit. Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 38.** Repeals and reenacts AS 43.55.025(c); requires an explorer to submit information to the commissioner of natural resources whether the geological objective of the well is a potential oil or gas trap; requires the commissioner to make the determination within a 60-day time period; requires qualifying exploration wells drilled outside of Cook Inlet to have a bottom hole not less than three miles away from the bottom hole of a preexisting oil or gas well; and requires the commissioner of natural resources to determine that the well adequately achieved the explorer's stated geological objective. The "definition of preexisting well" in current law is moved to sec. 43 of the bill where AS 43.55.025(k) is amended by adding the definition in a new paragraph. Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 39.** Amends AS 43.55.025(f) by adding an exception for a credit under AS 43.55.025(*l*) (AS 43.55.025(*l*) is a new subsection added by sec. 44 of the bill) and expanding the description of information required to be furnished to the Department of Natural Resources; describes the periods during which information submitted under this subsection to the Department of Natural Resources will be held confidential; requires the Department of Revenue to issue two production tax credit certificates, each for one-half of the amount of the credit allowed against production taxes; provides that the credit associated with one certificate may be used immediately and prohibits the application of the credit associated with the second of the two certificates before the calendar year following the year in which the certificate is issued; states that some information related to the production credit is not confidential. Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 40.** Amends AS 43.55.025(g) to prohibit an explorer that is exempt from the production tax from transferring, conveying, or selling a production tax credit certificate. Under sec. 71 of the bill, this section is retroactive to July 1, 2003.

**Section 41.** Amends AS 43.55.025(h) to refer only to AS 43.55.011(e), the subsection under which the tax is levied following the repeal and reenactment of AS 43.55.011(e) in sec. 15 of the bill, and the repeal and reenactment of AS 43.55.011(f) in sec. 16 of the bill. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 42.** Repeals and reenacts AS 43.55.025(i). The reenacted provision prohibits applying a tax credit to reduce a taxpayers tax liability below zero and allows tax credits that may not be applied for a calendar year to be carried forward to later calendar years. The reenacted provision is substantively similar to existing law. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 43.** Amends AS 43.55.025(k) by adding a new paragraph that defines "preexisting well." Under sec. 66 of the bill, this section applies to expenditures incurred after December 31, 2007, that are the basis for tax credits with respect to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 44.** Amends AS 43.55.025 by adding a new subsection -- AS 43.55.025(*l*) -- that relates to a claim for a production tax credit under AS 43.55.025 that is filed before January 1, 2016. Provides for a production tax credit equal to five percent of an eligible expenditure for seismic exploration performed before July 1, 2003; states the terms an expenditure must satisfy to qualify for the credit. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 45.** Adds a new section to AS 43.55 -- AS 43.55.028 -- that establishes the oil and gas tax credit fund and provides for the purchase by the department of certain transferable tax credit certificates issued under AS 43.55.023 and certain production tax certificates issued under AS 43.55.025. Money in the fund consists of earnings on the fund and appropriations to the fund out of production taxes levied under AS 43.55.011. Requires the Department of Revenue to manage the fund and to use money in the fund to purchase tax credit certificates that satisfy certain conditions. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 46.** Amends AS 43.55.030(a) to make the statement filing requirement apply to all producers rather than only those producers with a tax liability. Adds additional information requirements to those in current law. Under sec. 66 of the bill, this section applies to statements and reports required to be filed after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 47.** Amends AS 43.55.030(d) by making a person required to file a report under the section liable for a penalty of $1,000 for each day the person fails to file the report; provides that the penalty is in addition to existing penalties in AS 43.05.220 and 43.05.290; includes a statement within the meaning of "report" in the subsection.

**Section 48.** Adds subsections (e) and (f) to AS 43.55.030. AS 43.55.030(e) requires an explorer or a producer that does not produce oil or gas during the calendar year to report the producer's qualified capital expenditures and other lease expenditures; also requires a producer or explorer receiving a payment or credit under AS 43.55.170 to show whether a tax is due based on AS 43.55.160(d) or 43.55.170(b) and, if so, the amount of the tax. AS 43.55.030(f) authorizes the Department of Revenue to require monthly reports of information related to the determination of the amount of tax due under the chapter. Under sec. 66 of the bill, this section applies to statements and reports required to be filed after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 49.** Amends AS 43.55.040 by adding additional paragraphs that authorize the Department of Revenue to require a producer, explorer, or operator to file reports and records that the department considers necessary to forecast state revenue under AS 43.55, and authorizes a $1,000 a day penalty against a person who fails to file a report, statement, or other document required under that section.

**Section 50.** Adds a new section -- AS 43.55.075 -- to AS 43.55. AS 43.55.075 expands the limitation period for making an assessment of tax imposed by AS 43.55 from three years to six years after the latest return was filed. Requires a producer to report retroactive changes that affect an element used in determining the tax under AS 43.55 and to file amended returns for the periods affected by the change. Under sec. 66 of the bill, AS 43.55.075(a) applies to any tax liability for which the period of limitation had not expired as of the effective date of secs. 14 and 50 of the bill.

**Section 51.** Adds subsections (e), (f), and (g) to AS 43.55.110. AS 43.55.110(e) and (f) authorize the Department of Revenue to require filing and payment by electronic means; AS 43.55.110(g) authorizes the Department of Revenue to issue non-binding advisory bulletins stating the department's interpretation of AS 43.55 and regulations adopted under the chapter.

**Section 52.** Repeals and reenacts AS 43.55.160(a). Provides for the determination of the production tax value of oil and gas produced outside of Cook Inlet, oil produced in Cook Inlet, and gas produced in Cook Inlet. For oil and gas produced outside of Cook Inlet, the production tax value is the gross value at the point of production for that oil or gas, reduced by the lease expenditures and adjustments that are the costs of exploring for, developing, or producing oil located within the leases or properties, and, if the first reduction results in a positive number, lease expenditures and adjustments that are allocated to those leases or properties under AS 43.55.160(e) - (g). (AS 43.55.160(e) is

repealed and reenacted in sec. 54 of the bill; AS 43.55.160(f) and (g) are added by sec. 55 of the bill.) For oil and gas produced in Cook Inlet, the production tax value is the gross value at the point of production for that oil or gas, reduced by the lease expenditures and adjustments that are the costs of exploring for, developing, or producing oil located within the leases or properties. (The reenacted subsection removes the distinction between oil and gas produced north of 68 degrees North latitude and other oil and gas produced outside of Cook Inlet; however, the distinction between areas in the state continues in AS 43.55.160(f) and (g).) Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 53.** Amends AS 43.55.160(b) to refer to the tax value calculated under the section, rather than under only (a) of the section. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 54.** Repeals and reenacts AS 43.55.160(e). The reenacted provision addresses three situations in which a producer or explorer may have lease expenditure adjustments, part or all of which could be carried forward rather than being used during the current tax year: 1) the adjustments, if taken as a deduction would reduce the taxable value of oil and gas produced from a lease or property below zero; 2) the costs were incurred on leases or properties outside of Cook Inlet that did not produce oil or gas during the calendar year; 3) the costs are the producer's costs for the exploration for oil or gas located on land outside of Cook Inlet and in which the producer or explorer does not have an operating right, operating interest, or working interest. Before any such expenditures may be carried forward, the adjustments must first be allocated to those leases or properties under new subsections AS 43.55.160(f) and (g) (AS 43.55.160(f) and (g) are added in sec. 55 of the bill.) The current provision provides for a carry forward of adjusted lease expenditures if the adjustments would reduce the taxable value of oil or gas produced during the calendar year below zero. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 55.** Amends AS 43.55.160 by adding four new subsections -- AS 43.55.160(f), (g), (h), and (i). AS 43.55.160(f) provides for the allocation of adjusted lease expenditures that are the costs of exploring for, developing, or producing deposits within leases or properties that include land north of 68 degrees North latitude, and AS 43.55.160(g) provides for the allocation of adjusted lease expenditures that are the costs of exploring for, developing, or producing deposits within leases or properties outside of Cook Inlet and no part of which is north of 68 degrees North latitude. AS 43.55.160(h) describes "Cook Inlet excess adjusted lease expenditures" and provides the means by which excess adjusted lease expenditures attributable to Cook Inlet may be used to establish a carried-forward annual loss under AS 43.55.023(b) (AS 43.55.023(b) is amended in sec. 27 of the bill). AS 43.55.160(i) describes the calculations a producer subject to AS 43.55.160(h) is required to perform for determining the only amount of

excess adjusted lease expenditures that may be carried forward under AS 43.55.160(h). Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 56.** Repeals and reenacts AS 43.55.165(a), which describes a producer's lease expenditures. The reenacted subsection describes the types of costs that qualify and provides standards for the department to determine which costs may be allowed. The reasonable allowance for overhead expenses is moved into this subsection from the current AS 43.55.165(b). The reenacted AS 43.55.165(a) did not include from the existing provision references to typical industry standards in the state, costs an operator is allowed to bill to another working interest owner, and the standards used by the Department of Natural Resources when determining net profits for certain leases, as standards for determining lease expenditures. (The deleted reference standards are moved to AS 43.55.165(b) in sec. 57 of the bill.) Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 57.** Amends AS 43.55.165(b) by deleting the provision for the allowance of reasonable overhead expenses (which was moved to AS 43.55.165(a) in sec. 56 of the bill) and incorporating factors that appear in the current AS 43.55.165(a) for determining what costs are lease expenditures. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 58.** Amends AS 43.55.165(e) (relating to excluded lease expenditures) by deleting language in AS 43.55.165(e)(15) that relates to dismantlement, removal, surrender, or abandonment costs attributable to production before April 1, 2006, and adding additional categories of excluded costs. AS 43.55.165(e)(6) is amended to exclude costs that arise from a violation of law or the failure to comply with an obligation under a lease, permit, or license issued by the state or federal government. AS 43.55.165(e)(19) is added to exclude costs for repair, replacement, or deferred maintenance undertaken in response to an unscheduled interruption or reduction in the rate of production or undertaken in response to an unpermitted release of gas or other hazardous substances. (AS 43.55.165(e)(19) appears to address concerns similar to those addressed in HB 128 and SB 80, but uses different criteria than those in the existing legislation for determining excluded costs.) AS 43.55.165(e)(20) is added to exclude costs related to a refinery or crude oil topping plant, but allows the value of certain products produced from such a facility to be lease expenditures. Under sec. 66 of the bill, this section applies to oil and gas produced after March 31, 2006. Under sec. 71 of the bill, this section is retroactive to April 1, 2006.

**Section 59.** Amends AS 43.55.165(h) by specifying that the lease expenditures that are allocated are the costs of exploring for, developing, or producing oil or gas deposits. Under sec. 66 of the bill, this section applies to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, this section takes effect January 1, 2008.

**Section 60.** Amends AS 43.55.170(a) by deleting an exception relating to the subtraction of a payment or credit in calculating billable or billed costs. Under sec. 66 of the bill, this section applies to oil and gas produced after March 31, 2006. Under sec. 71 of the bill, this section is retroactive to April 1, 2006.

**Section 61.** Adds a new section to AS 43.55 -- AS 43.55.890. The new section provides for the publication of information, if aggregated among three or more producers or explorers, that includes the amount of oil or gas production, the amount of taxes levied and paid under AS 43.55, and other information related to credits, expenditures, and the value of oil and gas produced.

**Section 62.** Amends AS 43.55.900 by adding definitions for "non-unitized reservoir," "pool," "producer," and "unit."

**Section 63.** Repeals AS 43.55.023(f) (relating to refundable credits).

**Section 64.** Repeals AS 43.55.165(c) and (d) (relating to the determination of lease expenditures using operating agreements). Under sec. 66 of the bill, these repeals apply to oil and gas produced after March 31, 2006. Under sec. 71 of the bill, these repeals are retroactive to April 1, 2006.

**Section 65.** Repeals AS 43.55.011(*l*) (relating to the taking of a tax reduction for Cook Inlet production), 43.55.023(i) (relating to transitional investment expenditures occurring after March 31, 2001, and before April 1, 2006), 43.55.160(c) (relating to the determination of the production tax value of oil and gas taxable under AS 43.55.011(g)). Under sec. 66 of the bill, these repeals apply to oil and gas produced after December 31, 2007. Under sec. 72 of the bill, these repeals are effective January 1, 2008.

**Section 66.** Makes identified bill sections applicable to oil and gas produced after March 31, 2006 and after December 31, 2007, to expenditures incurred after December 31, 2007, to tax credit certificates that have not been refunded, and statements and reports required to be filed after December 31, 2007.

**Section 67.** Provides for the assignment of current oil and gas auditors in the Department of Revenue and the Department of Natural Resources and their immediate supervisors to the exempt service, but allows those individuals hired before the effective date of sec. 10 of the bill (adding these position classifications to the exempt service) to choose to continue in the classified service.

**Section 68.** Allows regulations adopted by the Department of Revenue and the Department of Natural Resources to be retroactively applied. Under sec. 71 of the bill, this section is retroactive to April 1, 2006.

**Section 69.** Provides for the treatment of pending applications for transferable credits and for the refund of credits under AS 43.55.023.

**Section 70.** Authorizes the Department of Natural Resources and the Department of Revenue to proceed with the adoption of regulations necessary to implement the Act but provides that an adopted regulation may not take effect before the effective date of the law being implemented.

**Section 71.** Provides for the retroactivity of certain provisions of the Act. The retroactivity is noted in the analysis of the bill sections above.

**Section 72.** Makes certain provisions of the Act effective January 1, 2008. The sections effective on this date are noted in the analysis of the bill sections above.

**Section 73.** Except as provided in sec. 72, makes the Act take effect immediately.

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# State of Alaska

**Department of Revenue**
*Commissioner's Office*

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The Honorable Mike Doogan
House District 25 Representative
716 West 4th Avenue
Anchorage, Alaska 99501
(907) 269-0216

October 17, 2007

Dear Representative Doogan,

Thank you for your questions and we look forward to working with you through the ACES process. Your original questions and the Department's answers are set forth below. Please let me know if you require any additional material.

1. *Deputy Commissioner Marcia Davis said at the outset that the administration wanted to fashion a tax plan that encouraged industry investment and enhanced stat revenue. Are these goals listed in priority order; that is, in instances that inevitable trade-offs arose between the two goals, were they decided in favor of investment over revenue?*

The two goals are of equal value. The balance of the two goals leads to the ultimate objective to maximize the total value of oil and gas resources received by the state.

2. *Was the failure to predict income from the existing PPT all attributable to higher costs being claimed by the industry? If not, what other factors led to the spectacular chasm between what had been predicted for PPT and what was paid?*

The difference between the PPT forecast and actual tax revenues was due primarily to the inaccurate nature of the cost information used in the forecast calculation. The fiscal notes provided during the 2006 PPT debate relied on a variety of sources, including reports of outside experts, public statements from the North Slope producers, and some 2002 – 2004 cost information provided by the producers. The current PPT law does not require industry to supply detailed information relating to past or future costs, making it difficult for the department to determine whether the increases were due primarily to increase prices on current investments (price per item), or from an increased level of investment activity (more items purchased). This is one of the primary reasons ACES seeks to make the companies/taxpayers report their costs to us in real time--and prospectively.

To some extent we know that costs increased as a result of increased prices. The department has verified a global price escalation that took place over the past two years due to both the global increase in material and labor costs due to increasing demand, and the North Slope specific renewal of many industry sub-contracts. The contracts negotiated by producers in late 2005 and 2006 were at substantially higher prices than their earlier contracts. The prior lower priced contracts were negotiated at a time when producers believed that oil prices would fall, and that belief suppressed the pricing of contractors who knew that work would only materialized if the oil and gas projects could be shown to be profitable at approximately $20 barrel oil. We anticipate costs to rise slightly more before leveling off after the coming fiscal year, as additional North Slope contracts are re-negotiated.

3. *Since there has been no auditing of costs claimed by the industry under PPT, what confidence can we have that the administration's revenue projections based on that data are accurate?*

For our projections we have used the costs filed by the producers in their tax returns. Until these returns are audited, the appropriateness and accuracy of the reported cost amounts remain open questions. It is unlikely that the industry has understated its costs

ACES contains provisions that will rectify the situation the administration currently faces. ACES will improve DOR projections through stricter reporting requirements that are not contingent solely upon tax returns. It will include the obligation to supply DOR with documentation that is currently supplied by the unit operators to the other unit working interest owners relating to budgetary matters. This information will contain the operators' forecasted costs for the next 12 to 18 months associated with the Unit's approved operations plan. While these plans can be changed by the working interest owners over time, the DOR will likewise be made aware of those changes real time.

In addition, current information will be made more readily and timely available to the DOR by the ACES provisions that (1) enhance the DOR's ability to hire a sufficient number of qualified oil and gas tax auditors to speed up our auditing process, (2) create a comprehensive, workable database where the data is derived via computer from standardized monthly and annual tax reporting forms, and (3) an extended statute-of-limitations to complete any assessments on filed returns, which will enable DOR to focus on high priority audits without concern that lower priority audits will be timed out.

4. *Insofar as the administration's plan is based on confidential information, how will the legislature be able to satisfy itself that such data is accurate and is being interpreted properly?*

The economic models created by DOR and DNR personnel that analyze various tax proposals were built using a substantial amount of confidential tax payer information, and confidential resource data, without which the models cannot be manipulated. We have been advised by the Department of Law that the legislature may only review this underlying confidential information when the legislature is in executive session and accompanied by signed confidentiality agreements. While this limits what we may allow legislator's to inspect prior to the start of the session, we are happy to share our methodology, including assumptions, so that legislators can understand the analytical underpinnings of the models as a first step to verifying the validity of their results.

5. *In what ways is the administration's tax plan "intended to drive new production?" What sort of research was performed to estimate the effect of the state's production tax policy on the industry's decisions to explore or develop? What other factors are involved? Where do state taxes rank in the hierarchy of industry decision-making?*

Investment decisions are influenced by a number of considerations including resource potential, tax structure, regulatory environment, infrastructure, political stability and many others. Although the resource itself is generally the most significant driver, each company must gage each of these elements according to its own strengths and investment objectives.

From a state's perspective, it is important to understand the relative value of its resource, in addition to how its other features compare to those of competing areas. The state's ability to acquire the greatest possible value for its resources, however, depends largely on the state's ability to understand and respond to investment behavior. This means that regulatory and fiscal systems must be structured in a way that allow companies to meet investor expectations efficiently, but allow the state flexibility in capturing the greatest share of the resource's economic rent.

In structuring a tax system, the state has many tools at its disposal which affect companies in different ways at different periods in a project's economic life cycle. The most significant elements affecting an area's investment attractiveness allow a company to recoup its initial investment dollars as soon as possible. Value contributed by the state through capital credits reduce an investor's up-front costs and have a much greater positive effect on a project's net present value than does a reduction in tax rates. When an oil company invests, its future cash flow has uncertainties because of unexpected reservoir performance, and uncertainty relating to oil price. The sooner it recovers its initial capital investment, the more able the producer is able to weather the downside risks associated with production and oil price.

Both royalties and production taxes reduce the net cash flow that a company receives in the same way that operating and capital expenses do. These factors were taken into

consideration in the Administration's modeling efforts, along with cost and sales price sensitivities.

The analysis done by the Administration was based on sampled range of real projects, currently posed for development in Alaska. We were able to model the impact of various tax structures on exploration and development of these projects within the context Alaska's cost environment. The analysis showed several interesting things.

One thing we found was that a straight gross tax rate, at anything like the rate that would be necessary to raise the kind of money that the state should expect to receive from its resource, resulted in quite unfavorable investment metrics across the development plays examined. We also examined a number of gross tax variations incorporating different exploration and development incentives, but were unable to find one that balanced our objectives as well as some of the net-based approaches.

6. *What is the history of industry investment in exploration and development in Alaska, in terms of dollars spent? Has Alaska's percentage of worldwide annual spending for exploration changed during the past 10 years?*

Please see attached documents.

7. *What happened to the "challenges of writing regulations for PPT" mentioned in the department's analysis of Aug. 3?*

The second round of regulations has been largely focused on describing lease expenditures and addressing joint interest auditing. The department anticipates that although challenges will remain, the ACES proposal will be more administrable and drafting regulations for ACES will be a simpler task.

ACES take a clearer approach to defining allowable lease expenditures by enabling the department to make determinations regarding what costs are included. The current PPT language requires the department make explicit exclusions, and to accept unit accounting conclusions regarding which costs qualify.

ACES also removes from consideration as leasehold expenses certain disputable classes of costs such as proportionate abandonment costs, crude oil topping plant costs, and replacement and repair costs associated with unscheduled reduced or shut in production, oil spills or gas releases. These clarifications greatly simplify the technical regulations relating to leasehold expenses.

8. *Is the administration considering contracting for auditors needed for any net profits tax?*

Yes. The department plans to use a contractor in the short-term, along with department auditors, for a compliance review focused on leasehold expenditures that is anticipated to begin immediately. The use of contractors, however, is not a sustainable solution for the state and are only planned to be used over the next 2-4 years. They will help to augment and fully develop the department's own upstream auditing ability and auditor training programs. Requirements for auditors will changes substantially during the first two years as our auditors are provided with the appropriate information.

9. *The original PPT was written as a method of getting a gas pipeline. Since that approach has failed, what will the administration be proposing for provisions that allowed producers to write gas line costs off against their oil taxes?*

The administration believes that a fair tax on oil should not impact the state's prospects for a gasline. ACES, as proposed, will not address the gasline directly but leave in place language from the existing PPT which disallows a gasline project from accruing certain credits (see below). The administration also believes that the most appropriate time to address any changes in the production tax as it applies to gas would be prior to the first open season, but at a time will more economic information is known about gas commercialization opportunities and gas projects are better defined.

AS 43.20.043 (f) of the existing PPT language states:
A taxpayer is not entitled to a credit under this section for expenditures that are made or incurred for the qualified capital investment or for qualified services made for exploration and development of gas that occur in the area of Alaska lying north of 68 degrees North latitude or that are made or incurred to transport gas from reserves located in the area of Alaska lying north of 68 degrees North latitude.

10. *What are the proposed credits for oil exploration and development credited against?*

The credits will offset liability for production taxes. To the extent a company's credits are larger than its production tax liability, the company may transfer credits to another taxpayer. In the case of qualified applicants that produce an average of 50,000 barrels per day or less, the applicant may seek a refund of the credits from the state.

**Tax liability = [(Value - Costs) x tax rate] - credits.**

**Value** = volume of oil x wellhead value*
**Costs** = allowable capital expenditures + operating expenditures
**Rate** = 25% + .2% for every dollar that net income** per barrel exceeds $30

*Wellhead value = ANS price – transportation costs (TAPS tariff)
* *Net income = Value - Costs

11. *What does allowing two years for claiming capital credits do to the state's revenue projections? How will the added uncertainty introduced into those projections by this provision be accounted for?*

We expect that allowing companies to claim capital credits for two years will actually improve the stability of the state's revenue projections. The effect of the 2 year spreading of costs is that a single high cost year gets spread over two years, muting its negative effect on state revenues. In addition, the state has an opportunity to anticipate and plan on the higher costs that will be experienced in the next ensuing year. Where costs are increasing steady state the state revenues experience no ill effect from the averaging across two years.

12. *What is a participating area?*

A participating area is a subset of an oil and gas unit that is considered reasonably proven to be capable of producing oil and gas in quantities that would enable the operator to earn a profit. By regulation, an Operator must form a participating area prior to production. The unit boundaries are surface boundaries. The participating area can be visualized as an underground water balloon, but with oil and/or gas as its contents, and the participating area's boundaries are the latex rubber balloon that encapsulates the oil and/or gas reservoir. Traditionally, most participating areas encapsulate the volume of oil and/or gas that is considered to be in communication and sharing the same reservoir pressure and other fluid and reservoir properties. Operators develop oil and gas fields within units on a participating area basis and the owners of leases that overlay any part of the participating area agree upon special Operating Agreement provisions to govern the operator's conduct of development of that Participating Area. The Operator submits and DNR approves a methodology for allocation of production and costs for the unitized leased acreage committed to the participating area.

13. *How much of the government take in the administration's charts is state take? What is included in state take, and how much is each of these segments worth?*

In our attempt to capture the state a fair share of Slope-wide revenues we have focused on the concept of the "share of the incremental dollar" or "marginal tax rate" ("MTR"), rather than "take."

The term "Government Take" refers to the percentage of economic rent going to government. This is the cumulative gross revenues less costs (before tax). It is a life-cycle concept involving all development costs, including a companies cost of capital. We use this concept in analyzing investment on new fields, where all (or most) of the costs will be incurred going forward.

'Take' does not work on legacy fields where most costs were incurred many years ago and have already been recovered. In addition, it does not work for examining a single

year, for if a lot of costs are incurred one year, and you are looking at take the next year, the results can be deceptive.

The Marginal Tax Rate (MTR) is derived by looking at total per barrel government revenues at one price, and then increasing the costs by one dollar. The difference in per barrel government revenues is the marginal tax rate. The MTR is appropriate when costs have been recovered, and it can be looked at for individual years. It is what many economists use to compare government revenues internationally.

Total government revenues include royalties (state, federal, and private), state property tax, state production tax, state corporate income tax, and federal corporate income tax. The relative amounts of these vary depending on price.

Under ACES, with our 2008 cost assumptions, at a $60/bbl U.S. West Coast ANS price, the marginal tax rate is about 69%. In other words, as the price of oil moves up one dollar, government gets 69 cents of that dollar. About 50 cents of that goes to Alaska, or about $4.6 billion. This is broken out as follows:

| | |
|---|---|
| Royalties | $1.9 B |
| Production tax (ACES) | $2.0 B |
| Property tax | $0.1 B |
| State corporate income tax | $0.6 B |
| | $4.6 B |

14. *If the government take is a measure of the net value of a barrel of oil, what is that net value? What has been taken out to reach it?*

See question 13

15. *Under what scenario would the gross floor kick in? Specifically, what would have to happen to oil price and/or costs to bring the gross floor into play? Why is the gross floor lower than the ELF take from Prudhoe Bay?*

The floor would kick in when the combination of prices and costs yields net income such that the tax derived under ACES would be less than a tax derived at 10% of the gross revenue at the point of production. Given our assumptions for cost in FY 2008, we estimate the floor would kick in for the combined legacy fields at $40 West Coast oil price.

Under ELF, the gross tax rate would have been 15% X the field-specific ELF. The 10% gross floor would kick in for Prudhoe at an ELF of 0.67. Our forecast would be for this to trigger in 2017. Prior to that, the ELF for Prudhoe Bay would still be above the 10% floor.

16. *Why does the gross floor provision require a less aggressive upside tax?*

There is the potential for significant new investment in both the Prudhoe Bay and Kuparuk River Units. A significant volume of known viscous and heavy oil is located within these two units, and its development will be costly. In addition, investments which slow the pace of decline by 1 or 2 percentage points can mean significant volumes of production at lower costs and thus result in significant revenue to the state. In balancing the lower costs associated with expanding existing developments in legacy fields with the importance of more costly new reservoir developments in these legacy fields, the administration struck a balance that more aggressively protected the state in a low oil price-high cost environment, and in return the administration left producers with a greater upside in the event of higher oil prices and lower costs. It is unreasonable to expect that the producers would proceed with high cost developments within legacy fields, having no protection on the downside, if there were not greater rewards received for taking the risks associated with costs and oil prices. Further, where enhancements to existing production in legacy fields have relatively lower costs compared to similar production volumes coming from new developments, this lower cost benefit is captured in the net tax structure, by lower costs being netted against gross revenues.

17. *The administration's world average figures use the mean "to kick out extreme numbers." If the extreme numbers are real, why would we kick them out?*

The purpose of looking at international "government take" numbers is to provide some guidance as to the fairness of the tax scheme. where "fairness" is measured against international norms. (Note that the notion of "government take" actually says very little about comparative investment attractiveness – which is also importantly a function of the size of the resource prize, and costs of exploration, development, and production.) The calculation of an "average" is indeed highly sensitive to data that falls in the extreme ends of the spectrum ("outliers") that is, an extreme value can significantly move the "average". However, an extreme value tells one little about "norms". The "median" statistic is not affected by outliers; accordingly, as a guide to fairness norms, the "median" provides more robust information.

18. *If, as we are told, North Slope oil production is declining by 6 percent a year, then next year we will be producing about 75,000 barrels a day less. If the administration's less aggressive upside tax leaves $1 a barrel on the table, what return in terms of exploration and development would make foregoing that $27,375,000 worthwhile?*

A: The administration's upside tax is not less aggressive than the current PPT structure. It proposes an increase in the net tax rate on legacy fields of 25% instead of the current 22.5%. In addition, ACES changes progressivity by having it begin at $30/bbl instead of PPT's current $40/bbl net income. While the rate of increase is slightly less aggressive (0.2% under ACES vs. 0.25% under PPT), the significance of the ACES' earlier start-up

is that PPT progressivity would not provide greater revenue to the state that that provided by ACES until oil prices were over $120/bbl.

Sincerely,

Pat Galvin, *Commissioner*
Department of Revenue

**Title:** **Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration**

Preparer: Chuck Logsdon, Greg Bidwell, and Cherie Nienhuis, Economists, Department of Revenue

Date: Updated 10/3/07

Purpose: Provide information to legislature on capital spending on the North Slope

Data Source: See sources on "Capex" sheet

Key Assumptions: None

History: Spreadsheet has been maintained and updated since the early 1990s.

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

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# Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

**Millions of nominal Dollars [dollars of the day]**

**All Companies**

| Year | Exploration | Development | Total |
|---|---|---|---|
| 1975 | | | 3,827 |
| 1976 | | | 1,166 |
| 1977 | | | 890 |
| 1978 | 274 | 400 | 674 |
| 1979 | 174 | 1,282 | 1,456 |
| 1980 | 176 | 1,604 | 1,780 |
| 1981 | 419 | 3,104 | 3,523 |
| 1982 | 647 | 3,839 | 4,486 |
| 1983 | 818 | 1,100 | 1,918 |
| 1984 | 258 | 1,193 | 1,451 |
| 1985 | 514 | 1,547 | 2,061 |
| 1986 | 288 | 771 | 1,059 |
| 1987 | 288 | 1,020 | 1,308 |
| 1988 | 36 | 765 | 801 |
| 1989 | 132 | 748 | 880 |
| 1990 | 96 | 1,061 | 1,157 |
| 1991 | 120 | 1,178 | 1,298 |
| 1992 | 216 | 991 | 1,207 |
| 1993 | 192 | 1,148 | 1,220 |
| 1994 | 72 | 808 | 892 |
| 1995 | 84 | 748 | 856 |
| 1996 | 108 | 826 | 922 |
| 1997 | 96 | 1,070 | 1,142 |
| 1998 | 72 | 1,560 | 1,608 |
| 1999 | 48 | 1,179 | 1,239 |
| 2000 | 60 | 1,545 | 1,697 |
| 2001 | 152 | 1,636 | 1,788 |
| 2002 | 126 | 1,054 | 1,180 |
| 2003 | 90 | 970 | 1,060 |
| 2004 | 67 | 980 | 1,047 |
| 2005 | 30 | 1,268 | 1,301 |
| 2006 | 123 | 1,591 | 1,714 |
| 2007 | 194 | 1,787 | 1,981 |

**Sources:** 1975-1989: Data from the "International Oil Tax Comparison Study", April 1990.
Study did not provide a breakdown by company and no detail for the years 1975-1977.
1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska.
Various published sources. A breakdown by company provided, but no breakout of
exploration cost and development costs. Exploratory costs assumed to follow
$12 million dollar per well rule of thumb.
2001-2004: Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports,
publications/extrapolations for others. Breakout of capex by company & type Capex spending.
2005-2007: Unaudited taxpayer submitted EIC and PPT credit information as of 10/3/07.
Exploration and development spending breakdown may contain inaccuracies, due to limited
information and to the fact that costs that do not qualify for exploration credits may qualify unde
the PPT as development capital credits.

# Alaska State Legislature

**Mike Doogan**
Representative
District 25, Anchorage


September 18, 2007

Commissioner Patrick Galvin
Alaska Department of Revenue
550 West 7th Avenue, Suite 1820
Anchorage, AK 99501

Dear Commissioner Galvin:

As I indicated, your briefing this morning on the administration's oil production tax proposal raised a variety of questions for me. I apologize if these questions seem scattershot. I am asking them in the order they occurred to me as the briefing progressed, not in any order of importance. Here goes.

1. Deputy Commissioner Marcia Davis said at the outset that the administration wanted to fashion a tax plan that encouraged industry investment and enhanced state revenue. Are these goals listed in priority order; that is, in instances that inevitable trade-offs arose between the two goals, were they decided in favor of investment over revenue?

2. Was the failure to predict income from the existing PPT all attributable to higher costs being claimed by the industry? If not, what other factors led to the spectacular chasm between what had been predicted for PPT and what was paid?

3. Since there has been no auditing of costs claimed by the industry under PPT, what confidence can we have that the administration's projections based on that data are accurate?

4. Insofar as the administration's plan is based on confidential information, how will the legislature be able to satisfy itself that such data is accurate and is being interpreted properly?

5. In what ways is the administration's tax plan "intended to drive new production?" What sort of research was performed to estimate the effect of the state's production tax policy on the industry's decisions to explore or develop? What other factors are involved? Where do state taxes rank in the hierarchy of industry decision-making?


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6. What is the history of industry investment in exploration and development in Alaska, in terms of dollars spent? Has Alaska's percentage of worldwide annual spending for exploration changed during the past 10 years?

7. What happened to the "challenges of writing regulations for PPT" mentioned in the department's analysis of Aug. 3?

8. Is the administration considering contracting for auditors needed for any net profits tax?

9. The original PPT was written as a method of getting a gas pipeline. Since that approach has failed, what will the administration be proposing for provisions that allowed producers to write gas line costs off against their oil taxes?

10. What are the proposed credits for oil exploration and development credited against?

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13. How much of the government take in the administration's charts is state take? What is included in state take, and how much is each of these segments worth?

14. If the government take is a measure of the net value of a barrel of oil, what is that net value? What has been taken out to reach it?

15. Under what scenario would the gross floor kick in? Specifically, what would have to happen to oil price and/or costs to bring the gross floor into play? Why is the gross floor lower than the ELF take from Prudhoe Bay?

16. Why does the gross floor provision require a less aggressive upside tax?

17. The administration's world average figures use the mean "to kick out extreme numbers." If the extreme numbers are real, why would we kick them out?

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That's what I've got right now. As a general matter, I'm concerned that the administration is trying to outguess the oil companies and influence those

companies' future decisions with a single tool – production taxes – that either (a) will not work or (b) will pay too much, in terms of foregone revenue, for the exploration and development it buys.

I look forward to your answers, and to further discussion of the administration's proposal.

Sincerely,

[Sent by e-mail]

Rep. Mike Doogan
House District 25

CC: Rep. Beth Kerttula, House Minority Leader
Rep. Kurt Olson, Chair, House Special Committee on Oil & Gas

# State of Alaska

Department of Revenue

*Commissioner's Office*

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## Sectional Analysis
## ACES

**Section 1:** Expresses legislative intent regarding application of the statute of limitations.

**Section 2:** Provides for the Department of Natural Resources to share with the Department of Revenue confidential information for use in administering the production tax or forecasting tax revenue, and maintains confidentiality.

**Sections 3-9:** No substantive change. Amends references to altered statutes.

**Section 10:** Provides for an exempt class of oil and gas auditors and supervisors.

**Section 11:** See sections 3-9.

**Section 12:** Makes conforming amendment regarding disclosure of certain taxpayer information. [See Sec. 61]

**Section 13:** Provides for the Department of Revenue to share production tax information with the Department of Natural Resources, and maintains taxpayer confidentiality.

**Section 14:** Makes conforming amendments regarding statute of limitations for production tax. [See Sec. 50]

**Section 15:** Repeals tax levy under PPT and establishes new oil and gas tax as calculated in following sections.

**Section 16:** Replaces current North Slope tax floor with new 10% gross tax floor on certain very large fields.

**Section 17:** Establishes net tax rate of 25% plus a progressivity factor of 0.2%.

**Section 18:** Lowers progressivity trigger from $40 per barrel to $30 per barrel (net) and provides for annual calculation instead of monthly.

**Sections 19-20:** Conforming amendments.

**Section 21:** Makes conforming change consistent with section 55, to the existing provision preventing Cook Inlet producers from utilizing Cook Inlet tax ceiling to export tax credits to other areas of the state.

**Section 22:** Changes the monthly installment tax calculations to conform to changes made by sections 15-18 and to take account of the existing Cook Inlet tax ceilings.

**Sections 23-25:** Conforming amendments.

**Section 26:** Limits to 50% the amount of a capital credit that may be claimed for a single calendar year; conforms data submission requirements for exploration capital credits to the data submission requirements for AS 43.55.025 exploration credits

[See Sec. 39]; Limits use of capital credits generated in fields subject to the 10% gross tax floor to taxes on oil and gas from those fields.

**Section 27:** Conforms the tax credit rate for carried-forward annual loss to the new basic net tax rate enacted by section 17, and provides that fields subject to the 10% gross tax floor may not carry forward losses.

**Section 28:** Conforming amendments for transferable tax credit certificates, increases from 60 to 120 days a time limit for Department of Revenue approval of certificates, and applies the 50% annual limitation in section 26 to certificates.

**Sections 29-30:** Conforming amendments..

**Section 31:** Clarifies that tax-exempt entities may not apply for transferable credit certificates.

**Sections 32-36:** Conforming amendments.

**Section 37:** Updates provisions for exploration credits, provides that a suspended well does not qualify for credits until completed or abandoned, and excludes costs arising from gross negligence or environmental or health and safety violations.

**Section 38:** Modifies eligibility provisions for exploration wells credits to better define and enforce the requirement to test a previously unexplored prospect while allowing for several exploration wells within a limited period of time.

**Section 39:** Clarifies the data submission requirements for exploration credits, reduces the confidentiality period for certain data, applies the 50 percent annual limitation in section 26 to exploration credits, and provides for public disclosure of basic information relating to credits.

**Section 40:** Clarifies that tax-exempt entities may not transfer exploration tax credits.

**Sections 41-42:** Conforming and clarifying amendments.

**Section 43:** Changes the definition of "preexisting well" for purposes of exploration credits to exclude wells drilled within 540 days rather than 150 days.

**Section 44:** Establishes 5% credit which may be claimed against seismic exploration expenses incurred before July 1, 2003, in exchange for seismic data, the acquisition of which is determined by the Commissioner of DNR to be in the best interest of the state.

**Section 45:** Creates Oil and Gas Tax Credit Fund for the purposes of purchasing certain tax credits from explorers and producers; Establishes procedure and standards for appropriation into and management of fund. (Replaces existing credit buy-back provisions [See Sec. 63])

**Section 46:** Requires producers to file annual report with the Department of Revenue annually, even if no tax is due that year, and expands examples of required information.

**Section 47:** Assesses penalty for late filing of reports required under sections 46 and 48.

**Section 48:** Requires producers and explorers to report certain expenditures and adjustments annually to the Department of Revenue and allows the Department of Revenue to require monthly reporting of information considered necessary for administering of taxes.

**Section 49:** Authorizes the Department of Revenue to require reporting of information needed for revenue forecasting purposes and to assess penalties for failure to timely file reports.

**Section 50:** Extends statute of limitations for production tax to six years, subject to extension due to changes in federal income tax, and provides for tax effects of retroactive changes in items that affect a producer's tax.

**Section 51:** Allows the Department of Revenue to establish and require electronic filing and payment.

**Section 52:** Clarifies how production tax values (i.e., taxable values) of oil and gas are calculated, consistent with changes enacted by sections 15-18.

**Section 53:** Makes conforming amendments required under section 52.

**Sections 54-55:** Further implements the changes enacted by section 52, providing for allocation of lease expenditures among leases or properties, and specifies an "anti double-dipping" provision with respect to Cook Inlet tax ceilings.

**Section 56:** Amends the description of deductible lease expenditures, provides that only expenditures allowed by regulation may be deducted, and makes terminology for overhead expenses consistent with ordinary usage.

**Section 57:** Conforms with section 56; existing language is moved to a different subsection.

**Section 58:** Makes non-deductible all expenditures for dismantlement, removal, or restoration; for repair, replacement, or repair associated with interruption of or reduction in oil or gas production or releases of oil, gas, or other substances; and for refineries or topping plants; allows for deduction of added value of refinery or topping plant products used in lease operations.

**Section 59:** Clarifies language of existing provision on cost allocation.

**Section 60:** Conforming change regarding repeal of certain provisions (see section 63).

**Section 61:** Authorizes Department of Revenue to publish production tax information if aggregated among at least three producers or explorers.

**Section 62:** Adds definitions needed for other provisions of Act.

**Section 63:** Repeals transitional investment expenditure (TIE) tax credit; repeals provisions for using unit operating agreements to determine deductible lease expenditures; Repeals existing provisions for state refund of certain tax credit certificates and makes conforming repeals.

**Section 64:** Applicability provisions: most substantive tax changes apply starting January 1, 2008; several apply back to April 1, 2006.

**Sections 65-68:** Transition provisions.

**Section 69:** Makes certain provisions of the act retroactive consistent with section 64; Makes section 40 retroactive to beginning of exploration tax credit program (July 1, 2003).

**Section 70:** Provides for January 1, 2008, effective date for most substantive changes to production tax.

**Section 71:** Establishes immediate effective date for Act other than as provided by section 70.

**Governor's Proposed Production Tax Legislation**

**October 1 2007**

**Sectional Analysis**

**Authors: Dan Dickinson & Steve Porter**

**Section 1 Uncodified Laws (Legislative Intent)**

Legislative Intent – refers to changes made in Section 50, page 31. It suggests that the changes are only clarifying a long-standing interpretation of AS 43.05.260 by the Department of Revenue (DOR). Details will be discussed in Section 50.

**Section 2 AS 38.05.035(a)**

This section allows the DOR access to the Department of Natural Resources (DNR) confidential information for

1) its use in forecasting state revenue under AS 43.55 or

2) administering AS 43.55, the production tax

In an apparent stylistic change this draft deletes previously repealed portions of AS 38.05.035(a) requiring subsections references to change as indicated in bill sections 3-9 below.

**Section 3 AS 38.05.036(b)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 4 AS 38.05.036(f)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 5 AS 38.05.036(g)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 6 AS 38.05.123(f)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 7 AS 38.05.133(e)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 8 AS 38.05.180(j)(6)(B)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 9 AS 38.05.275(c)**

Conforming references in Title 38 required by renumbering in sec. 2 of the proposed legislation.

**Section 10 AS 39.25.110(42)**

Section 39.25.110 is exempt service. This section adds oil and gas auditors performing production tax auditors and their immediate supervisors to the exempt service. This leaves oil and gas income tax auditors in the classified service.

**Section 11 AS 41.09.010(d)**

Conforming references in Title 41 required by renumbering in sec. 2 of the proposed legislation.

**Section 12 AS 43.05.230(a)**

Section 43.05.230 covers disclosure of tax returns and reports. Section 43.05.230(a) (5) adds a reference to AS 43.55.890. The reference to AS 43.55.890 (new section discussed in Section 61) in the proposed legislation would create an exclusion for certain information if aggregated

among three or more producers or explorers. This type of information would be allowed under AS 43.05.230(e) if the publication of the statistics was so classified as to prevent the identification of a particular tax payer's return or report. The new section would seem to lower the standard. This proposal would permit information which was "aggregated among three or more producers or explorers" to be divulged to the public even if, for example, a very large taxpayer's information was aggregated with two very small taxpayers so that the large taxpayer's individual taxpayer information could easily be extracted from the information disclosed.

**Section 13 AS 43.05.023(h)**

The Department of Revenue currently has the authority to share copies of returns, reports, and documents filed under AS 43.65 (Mining License Tax) with DNR. This language broadens the authority of DOR to also share returns, reports and documents filed under AS 43.55 (Oil and Gas Production Tax and Oil Surcharge) with DNR.

**Section 14 AS 43.05.260(a)**

This section adds AS 43.55.075 (Section 50 of this legislation) to the exceptions to the requirement to have taxes imposed within three years after a return is filed. Details will be discussed in Section 50.

**Section 15 AS 43.55.011(e)**

The current production tax is calculated on a monthly basis. In the proposal tax would be calculated based on a calendar year. This structure of the law is also changed. Currently AS 43.55.011(e) establishes the base tax rate (22.5%), and progressivity was dealt with elsewhere. However now this section refers to the percentage determined in AS 43.55.011(g) where both the base and progressivity rates would be established. This simplifies the comparison with the floor in AS 43.55.011 (f) - which is compared with a combined base and progressivity tax.

**Section 16 AS 43.55.011(f)**

This section makes changes to the minimum tax.

The current minimum tax is applied is 4% of gross value at the point of production over $25, 3% of gross over $20, 2% of gross over $17.50 and 1% of gross over $15 and 0% for $15 and under. The new minimum tax is 10% of gross value at the point of production.

The current minimum tax is applied to all oil and gas produced north of 68 degrees North latitude, i.e. the entire North Slope. The proposed minimum tax would apply only to oil and gas produced from leases or properties within a unit or non-unitized reservoir that have cumulatively produced one billion BTU equivalent barrels of oil or gas and from which the average daily oil and gas production during the most recent calendar year exceed 100,000 BTU equivalent barrels. Based on this limitation, the new minimum tax would only apply to oil and gas produced at Prudhoe Bay and Kuparuk.

The current floor compares net values to gross values, and then allows certain credits to be applied against the result – even against the floor. The proposed floor test compares 25% of net plus any progressivity less any credits with 10% of gross. If 10% of gross is higher, that is the tax and a taxpayer may not apply tax credits to reduce its tax liability to below 10 percent of total gross value at the point of production.

**Section 17 AS 43.55.011(g)**

This section proposes a tax of 25 percent plus 0.2 percent times the progressivity price index, defined in .011(h), however the sum is not to exceed 50 percent. The current law is 22.5 percent

plus 0.25 percent times the progressivity price index, however the sum is not to exceed 47.5 percent.

**Section 18 AS 43.55.011(h)**

This section amends the price index from a monthly calculation to a calendar year calculation.

This section also changes the starting net value of progressivity from $40 to $30 a barrel.

**Section 19 AS 43.55.011(j)**

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

**Section 20 AS 43.55.011(k)**

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

**Section 21 AS 43.55.011(m)**

This section clarifies what a producer could claim in excess credits from Cook Inlet against taxes on leases or properties elsewhere in the state.

If the amount of excess adjusted lease expenditures multiplied by 25 percent is greater than or equal to the total of the reductions for all leases calculated under the Cook Inlet ceilings in AS 43.55.011(j) or (k) , the total calculated under this paragraph would be zero.

Otherwise the remainder calculated by subtracting the excess adjusted lease expenditures multiplied by 25 percent from the total of the reductions for all leases calculated under AS 43.55.011(j) or (k) would be the total calculated under this paragraph.

This language is currently found in regulation at 15 AAC 55.360 (d)

**Section 22 AS 43.55.020(a)**

This section would reconcile the monthly installment payments of tax to be consistent with other proposed changes, and incorporates some regulatory solutions to some of the ambiguities in the existing legislation concerning Cook Inlet ceilings and credits that could only be applied on an annual basis.

**Section 23 AS 43.55.020(d)**

Conforming changes recognize that both the base and progressivity taxes would be levied in section .011(e) in the proposed legislation.

**Section 24 AS 43.55.020(g)**

Reference changes and clarifies annual due date.

**Section 25 AS 43.55.020(h)**

Reference changes and clarifies annual due date.

**Section 26 AS 43.55.023(a)**

This section stipulates that no more than half of a capital expenditure tax credit may be applied in a single year.

Section AS 43.55.011(f) states that a tax credit may not be applied to reduce a producer's tax liability below 10 percent of the total gross value at the point of production. This section deals with the excess tax credit left over after a producer reduces their tax to 10% of gross. This section stipulates that the excess tax credit left over may not be used to reduce the producer's taxes outside that unit.

A significant portion of the language -which had originally been copied from section .025 –would now be invoked by referencing AS 43.55.025(f).

**Section 27 AS 43.55.023(b)**

This section changes the amount of carried-forward annual loss that may be taken as a tax credit from 20 percent to 25 percent. (In current law the loss carry-forward at 20% does not equal the base tax rate at 22.5% percent.)

This section also prevents lease expenditures subject to AS 43.55.011(f) i.e., Prudhoe and Kuparuk, from contributing to a carried-forward annual loss.

**Section 28 AS 43.55.023(d)**

This section would end the ability to transfer or obtain a cash payment for an unused tax credit under AS 43.55.028 (new section) if that unused tax credit is described in the floor sections (i.e. Prudhoe Bay or Kuparuk.)

This section changes the time period that the department has to grant or deny the application from 60 days to120 days and amends the language that designates the start of the 120 day period.

This section also splits the certificate into two transferrable tax credit certificates, one that is available to use any time and the other that is not available until the next calendar year.

**Section 29 AS 43.55.023(e)**

Conforming changes to changes made in the proposed legislation.

**Section 30 AS 43.55.023(g)**

Conforming changes to changes made in the proposed legislation.

**Section 31 AS 43.55.023(l)**

This new section clarifies that an entity which is exempt from tax under the chapter cannot apply for a transferable tax certificate (for example the Alaska Natural Gas Development Authority or the Alaska Gasline Port Authority.) See section 40

**Section 32 AS 43.55.024(a)**

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

**Section 33 AS 43.55.024(c)**

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

**Section 34 AS 43.55.024(e)**

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

**Section 35 AS 43.55.024(g)**

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

**Section 36 AS 43.55.025(a)**

Proposal changes law so .024 credits cannot be applied against the tax floor in .011 (f).

**Section 37 AS 43.55.025(b)**

This section changes the date for expenditures for work performed to be eligible for a production tax exploration credit from July1, 2003 to December 31, 2007. (That is, even if this bill becomes law, the old rules will apply through December 31, 2007.)

This section adds the obligation that a well must be "completed or abandoned" at the time the explorer claims the exploration credit. Application would not be allowed prior to finishing the well.

This section would exempt costs arising from gross negligence or violations of Health Safety & Environmental statutes or regulations from expenditures that qualify for the exploration credit.

**Section 38 AS 43.55.025(c)**

The current law requires a well to be drilled 3 miles away from a preexisting well to be eligible for a credit, except in CI, where DNR can certify that the well tests a "distinct exploration target". The proposed law would require

(1) That the well be drilled to a structural or stratigraphic trap that is distinctly separate from any trap that has been tested by a preexisting well, with this determination made by the commissioner of DNR before the well is spudded;

(2) The existing three mile requirement for all wells not in the CI, and

(3) The commissioner of DNR to determine, after the well is completed or abandoned that the well adequately achieved the explorer's stated objective.

**Section 39 AS 43.55.025(f)**

This section defines what data would be necessary to be submitted to claim an exploration credit. The new language clarifies the obligation of the explorer to provide the DNR with all seismic data, on state lands and off state lands, within and outside unit boundaries.

In the case of well data the proposed legislation reduces the time period the data is required to be kept confidential from 10 years to 2 years. In addition AS 31.05.035(c) allowed an explorer to request the DNR to extend the time of confidentiality from 2 years for as long as necessary. The proposed legislation in (D) prohibits the explorer from requesting an extension if they want the credit.

This section also explains that the certificate issued will be two certificates, each for half the credit, one to be used whenever the explorer wants and one not to be used before the next calendar year. All certificates will have the date on which the information required to be submitted will be released.

**Section 40 AS 43.55.025(g)**

This new section clarifies that an entity which is exempt from tax under the chapter cannot transfer a transferable tax certificate (for example the Alaska Natural Gas Development Authority or the Alaska Gasline Port Authority.) See section 31

**Section 41 AS 43.55.025(h)**

Proposal changes law so .025 credits cannot be applied against the tax floor in .011 (f).

**Section 42 AS 43.55.025(i)**

Proposal changes law so .025 credits cannot be applied against the tax floor in .011 (f), and recognizes the proposed change from a monthly to an annual tax.

**Section 43 AS 43.55.025(k)**

This section changes the definition of preexisting well from a well spudded more than the150 days to 540 days in the proposed legislation. In other words, it expands the window to qualify as an exploration well from one season of work to two seasons, and thus may include delineation wells.

**Section 44 AS 43.55.025(l)**

This new section would allow the DNR approve a credit for seismic shot prior to July 1, 2003 if the Commissioner of DNR finds it in the best interest of the state to acquire the seismic for public distribution. The credit would be 5% of the old investment expenditure.

**Section 45 AS 43.55.028**

This section would create an oil and gas tax credit fund to purchase certain transferrable credit certificates issued under AS 43.55.023. The amount of revenue deposited into the fund would be based on the average price value forecast by the DOR of ANS oil sold on the West Coast. For $60 or higher the percentage is 10%; for less than $60 the percentage is 15%. For example,

the current forecast by the DOR for 2008 is $51.25; so 15% of all revenues production tax received during 2008 would go to the fund after deposits to the CBR. Production tax revenues for 2008 are forecast to be $995.4 million; so, the deposit to the fund would be approximately $150 million. If the DOR projections are wrong or the tax is increased, the amount going into the fund would be different.

The department would be able to use the fund to purchase tax certificate but the purchase could not exceed the amount incurred by the applicant for qualified capital expenditures or lease bonuses in the 24 months subsequent to the application. The applicant's total production cannot exceed 50,000 BTU equivalent barrels per day, thus excluding the 3 largest taxpayers. All the qualifications currently found in AS 43.55.023 (f) (which is repealed under this proposal) have been retained, except the maximum of $25 million a year to each taxpayer

**Section 46 AS 43.55.030(a)**

This section would amend what a tax payer is required to file by March 31st of the following year. It makes explicit the requirement to submit the costs for transportation of the oil and gas, qualified capital expenditures, and lease expenditures under AS 43.55.165 and 170, the production tax value of the oil and gas, and any claims for credits.

**Section 47 AS 43.55.030(d)**

This section defines the penalties of up to $1,000 a day for not filing the required reports.

**Section 48 AS 43.55.030(e-f)**

Section (e) would add a reporting obligation to explorers that do not produce oil or gas.

Section (f) details what the department could require of a producer, explorer, or operator on a monthly basis.

**Section 49 AS 43.55.040**

This section would add a clause to the powers of DOR giving them the right to require a producer, explorer or operator to file reports that are "considered necessary" to forecast state revenue under AS 43.55. To the degree that this lines up with statutory authority (37.07.060 (b) (4), the forecast is for the current and next fiscal year; however the limitation is not explicit.

The section also provides for penalties of up to $1,000 a day for a person that does not file the reports "considered necessary" by the department.

**Section 50 AS 43.55.075**

This section was referred to in the legislative intent language of the proposed legislation – which recognizes that historically most production tax audits took longer than 3 years and relied on AS 43.05.260(c) (3) which permits a longer audit if the "taxpayer ... consented in writing". The proposal requires the amount of tax imposed by this chapter to be assessed within 6 years after the latest return is filed. The section also details various filing time period obligations.

**Section 51 AS 43.55.110(e-f)**

Section (e) allows the department to require electronic filing

Section (f) allows the department to require electronic payments

**Section 52 AS 43.55.160(a)**

This section is a simplified rewrite of existing law, a consequence of no long having to do monthly calculations for progressivity.

**Section 53 AS 43.55.160(b)**

Continues the simplification from the prior section

**Section 54 AS 43.55.160(e)**

The proposal would expand section (e) to include among the costs that may be used to generate loss carry forwards those costs associated with leases of a producer that are not producing oil and gas or are on lands where the producer does not own an operating or working interest.

**Section 55 AS 43.55.160(f-i)**

This section deals with allocations of costs that a taxpayer incurs in one lease or property against revenues from another lease or property. Proposed North Slope rules are in (f), New Area Development rules are in (g) and Cook Inlet rules are in (h) and (i). This section would import regulatory language into the statute:

Section (f) clarifies that costs subject to the floor in AS 43.55.011(f) could not be allocated to other leases or properties. Otherwise costs must be allocated to producing properties

Section (g) applies to leases outside the North Slope and outside Cook Inlet, in other words costs that qualify for the .024 new area development credit. Those expenditures must be applied to leases outside the North Slope and outside Cook Inlet.

Section (h) deals with CI allocations and which costs (defined as "Cook Inlet excess adjusted lease expenditures" ) can be used in calculating carried-forward annual loss These rules are currently found in regulations in15 AAC 55.235.

Section (i) sets forth the calculations for determining the carried-forward annual loss in (h), using rules currently found in regulations in 15 AAC 55.223.

**Section 56 AS 43.55.165(a)**

Section (a) is rewritten and would delete the "typical industry practices and standards" language in the current legislation. The language that is deleted from (a) is inserted in (b).

**Section 57 AS 43.55.165(b)**

Section (b) was modified by deleting reasonable allowance language that was inserted in 165(a).

**Section 58 AS 43.55.165(e)**

The current law allows for the costs for dismantlement, removal, and surrender or abandonment (DR&R) to qualify as lease expenditures if they are incurred after April 1, 2006. The proposed legislation would disallow all dismantlement, removal and surrender or abandonment costs to qualify as lease expenditures.

Section (19) was added to (e). It would disallow costs incurred for repair, replacement, or deferred maintenance that is undertaken in response to a failure or problem that results in an unscheduled interruption or reduction in the rate of oil or gas production.

Section (20) was added to (e). It would disallow costs of refineries or crude oil topping, plants, including those on the North Slope that produce fuel for North Slope production operations. Instead a taxpayer will be allowed a deduction for what it (and the State's auditors) reckons is the "fair market value" for refinery products less the underlying value of the oil used in the refinery.

**Section 59 AS 43.55.165(h)**

The original language of this section directed the department to write regulations where (as in CI under .011(j) and .011(k)) lease costs need to be allocated between oil production and gas production. The proposed change would expand that directive to include any required allocation of costs.

**Section 60 AS 43.55.170(a)**

This section would delete qualifying language regarding payment or credit that has already been subtracted in calculating billable or billed costs under AS 43.55.165(c) or (d).

**Section 61 AS 43.55.890**

This is a new section regarding the disclosure of tax information. It would allow the department to publish certain information if the information is aggregated from three or more producers or explorers. The potential impact of this change was previously discussed in Section 12.

**Section 62 AS 43.55.900**

This section adds the definitions of "non-unitized reservoir", "pool", "producer", and "unit".

**Section 63 Repeals**

This section would repeal the following:

AS 43.55.023(f), (State purchase of certain credits),

AS 43.55.165(c), (Use of operating agreements)

AS 43.55.165(d), (Use of audits under operating agreements)

AS 43.55.011(l), (Ordering of CI taxes against credits)

AS 43.55.023(i), (Transitional Investment expenditure credits),

and AS 43.55.160(c), (Monthly allocation of annual costs).

**Section 64 Uncodified Laws**

This section stipulates the applicability dates for each of the sections. In general, the new rules would become effective January 1, 2008, except for the deferred maintenance/corrosion provisions of .165 (e) (19) which would be retroactive to April 1, 2006.

**Section 65 Auditors**

This section would assign oil and gas auditors to exempt service.

**Section 66 Retroactivity of Regulations**

This section stipulates the dates on which the regulations implementing this statute could apply.

**Section 67 Pending Applications**

This section stipulates how to handle credit applications that are currently pending before the Department and have not been approved.

**Section 68 Regulations**

This section would grant DOR and DNR the authority to adopt regulations necessary to implement this legislation.

**Section 69 Retroactivity**

This provision explicitly provides that certain provisions of the act are retroactive to specific dates.

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Statute Section is AS 43.55.xxx unless other wise indicated

## Base Rate

| Issue | Bill Section | Statute Section | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|---|---|
| Base Rate | 15, 17 | .011(e) & (g) | 22.5% | 25% |

Tax on Private royalties under .011 (i) not changed (section 23 corrects reference)

## Progressivity

| | | | | |
|---|---|---|---|---|
| Difference subtracted from net (Production Tax) Value to Arrive at Price Index - (i.e. progressivity starting point) | 17, 18 | sec .011(g) & (h) | $40 | $30 |
| Progressivity Tax per dollar of Price Index | 17, 18 | .011(g) & (h) | 0.25% | 0.20% |
| Progressivity Calculation Averaged over what Period? | 17, 18 | .011(g) & (h),.160 (a) | Month | Year |

## Floor

sections 15,16, and sections 32-36, 41-42 to remove ability to apply credits

| | | | | |
|---|---|---|---|---|
| Base | 16 | .011(f) | Entire North Slope collectively, before application of credits | Prudhoe & Kuparuk, Individually (no other fields come close to 1 billion barrel standard), after application of credits |
| Gross Calculation | 16 | .011(f) | No change: Gross Value at Point of Production | |
| Rate | 16 | .011(f) | ranges from 0% to 4% | 10% |
| Can credits be applied to further reduce tax if floor applies? | 16 | .011(f) | Exploration (.025) and Non Transferable (.024) credits can be applied against floor, Investment and all other .023 credits cannot | No |
| Status of credits not used because of floor | 16 | .011(f) | implicit: can be carried forward, or applied to non North Slope areas | explicit: only applied against that legacy field: when carried forward |

## Credits

## Investment & Loss Forward Credits (.023 Credits)

| | | | | |
|---|---|---|---|---|
| Investment Credits | 26 | .023(a) | Taken in year of investment | Maximum of 50% of any year's credits taken in that year. |
| Applied against tax due under floor? | 26 | .023(a) | No change: .023 credits cannot be applied against tax due calculated under the floor | |

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Statute Section is AS 43.55.xxx unless other wise indicated

## Investment & Loss Forward Credits (.023 Credits) cont.

| Issue | Bill Section | Statute Section | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|---|---|
| Loss Carry Forward Credits | 27 | .023(b) | 20% | 25% |
| Restrictions on use of Loss Carry Forward Credits | 27 | .023(b) | no similar restriction | explicit: if costs occurred in legacy field subject to floor, loss can only be applied against that field. |
| Restrictions on use of Purchased Credits | 28,29 | .023(d) | Can be taken any time although cannot be applied against more than 20% of tax due | 50% of credit cannot be taken until following year. (retains 20% rule) |
| Transitional Investment Credits | 63 | .023(i) | Qualified investment from 2001 - 2006 used as a credit at 10% if matched by new investment. | eliminated |

## Nontransferable Credits (.024 Credits)

| | | | | |
|---|---|---|---|---|
| Applied against tax due under floor? | 41,42, 32-36 | .024 (a),(c),(e), (g) | Yes | No |

## Exploration Credits (.025 Credits)

| | | | | |
|---|---|---|---|---|
| Applied against tax due under floor? | 36, 41 | .025(a) & (h) | Yes | No |
| Disallowances | 37 | .025(b) | "administration, supervision...management... community relations or environmental costs..." not allowed | adds "costs arising from gross negligence or violations of health, safety, or environmental statutes or regulations" to costs not allowed |
| DNR approval and 3 mile rule for 40% credit | 38 | .025(c) | Bottom whole must be more than 3 miles from previously drilled bottom hole, except in CI, if DNR determines "distinct exploration target" | Before drilling DNR must make determination that new target "distinctly separate from any trap that has been tested by preexisting well," and after drilling DNR must determine well achieved objective and if not in CI bottom hole must be 3 miles from previously drilled bottom hole. |

note: .025(d) and (e) unchanged

Statute Section is AS 43.55.xxx unless other wise indicated

## Exploration Credits (.025 Credits) Cont.

| Issue | Bill Section | Statute Section | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|---|---|
| Data Explorer must submit to DNR | 39 | .025(f)(2) (A)&(B) | explorer must provide DNR with list of "data sets available" | Detailed list of data |
| Confidentiality of Well Data | 39 | .025(f)(2) (c) | 10 years | 24 months |
| note: Seismic data still at 10 years | | | | |
| Applicability of Credit Certificates | 39 | .025(f)(5) | Can be used immediately | 2 certificates, each for 1/2 of amount, one certificate cannot be used until the following calendar year |
| Non Confidential Information | 39 | .025(f)(5) | under general tax confidentiality rules | Explorer, location and date of work and when it will become public is public |
| Tax Exempt Entities Ability to Sell Credits | 31,40 | .025(g) | not mentioned | not allowed |
| Applied Against Tax Due under Floor? | 36, 41,42 | .025(a), (h) and (i) | Yes | No |
| Definition of Pre-Existing Well - in Effect Whether Delineation Wells Qualify for Credits | 43 | old .025 (c)(2)(a) new .025(k)4 | preexisting well is one that was spudded more than 150 days and less then 35 years earlier. Limits ability to come back next season and get credit for delineation well. | preexisting well is one that was spudded more than 540 days and less then 35 years earlier. Allows two seasons worth of work to qualify for credit. |
| note: .025(i) appears to have also been rewritten for clarity in section 42 and definitions are moved to (k) in section 43 or added in 62 | | | | |
| "DNR TIE" Seismic Credits | 44 | .025(l) | none | If DNR deems "best interests of state" served by acquisition and distribution of seismic data shot before 2003, a 5% credit allowed for cost. |

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Statute Section is AS 43.55.xxx unless other wise indicated

## Allowable Lease Expenditures

.160 great simplified in sections 52, 53 and 63 as monthly reporting calculations no longer needed.

| Issue | Bill Section | Statute Section | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|---|---|
| Carry Forward of Unused Lease Expenditures | 54 | .160 (e) | Lease expenditures that would reduce production tax values below zero can be used to establish a loss carry forward credit under .023(b) | Adds two more categories that can be used for carry forward credit: costs not associated with production or ownership interests |
| .165 Reorganized for clarity and as to between what is in (a) and what is in (b) in sections 56 & 57 | | | | |
| Cost must allowed in department's regulations? | 56 | 165(a) | no | yes |
| Use Portions of Existing Cost Sharing Agreements or intra-producer audits to determine costs? | 63 | .165(c) & (d) | allowed | not allowed |
| DR&R Allowed? | 58 | .165(e) (15) | allowed for portion allocated to production after April 1, 2006 | not allowed at all |
| Deferred Maintenance allowed? | 58 & 64 | new .165(e) (19) | Allowed | not allowed if undertaken in response to an problem which required a reduction in production, unless caused by something unavailable even to someone exercising due care. |
| Field Topping Plants allowed? | 58 | new .165(e) (20) | Allowed | not allowed; however a deduction for the 'fair market value' of the products from the topping plant will be allowed. |

## State Purchase of Credits

| | | | | |
|---|---|---|---|---|
| Funding of Purchase of .023 and .025 Credits by State | 30,45 | new.028 replaces .023(f) | "subject to appropriations made by law" | Creates the oil and gas credit fund, which is funded by 10% or 15% of production taxes depending on whether ANS WC is forecast (when?) to above $60 or below $60. Credits are purchased from fund. |
| Limits on Purchase of .023 and .025 Credits by State | 30,45 | new.028 replaces .023(f) | Entity receiving refund had to (i) have been producing fewer than 50,000 bbls a day (currently all but big three); (ii) reinvest that money in state, (iii) had no other delinquent taxes and (iv) was limited to $25 million a year | Same restrictions except $25 million cap eliminated |

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Statute Section is AS 43.55.xxx unless other wise indicated

## Information

| Issue | Bill Section | Statute Section | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|---|---|
| Required Reporting of Forward Looking Information | 49 | .040 (5) | none | requires taxpayer "to file report and copies of records that are considered by the department as necessary to forecast state revenues under AS 43.55". For unit with multiple working owners limited to unit budget matters. Penalty of not more than $1000 a day. Not clear how far in advance data must be disclosed to avoid penalty. |
| Disclosure of Tax Information | 61 | old 43.05.230 new .890 | Published information must combine data. so as to "prevent the identification of particular returns." | As long as data is aggregated among 3 producers 11 categories of data can be made public (production, taxes, effective tax rates, gross value, costs, production tax value and credits). Such aggregation is explicitly "irrespective of whether the information...prevents[s] the identification of particular reports." (i.e. one large taxpayer aggregated with two very small taxpayers) |
| DNR Sharing Royalty Information with DOR | 2-9 & 11 | royalty statutes | limited ability | expanded ability |
| DOR Sharing Tax Information with DNR | 12-13 | AS 43.05.230 | limited ability | expanded ability |
| Required Reporting | 46 | .030(a) | "The person paying the tax..." will report "with other information required" certain data | Producer (whether tax due or not) will report same information plus certain cost, credit and monthly data. Penalty of not more than $1000 a day. |
| Required Reporting | 48 | .030(e) & (f) | some requirements in regulations | in statute: thorough reporting of costs, volumes, sales, monthly estimates and other information required by department |

Detail Comparison Between Governor's October 1 2007 Production Tax Bill and Current Law

Statute Section is AS 43.55.xxx unless other wise indicated

## Statute of Limitations

| Issue | Bill Section | Statute Section | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|---|---|
| Statute of Limitations | 1, 14, 50 | old 43.05.260 new .075 | 3 Years for all Taxes | 6 years for Production Tax |

## DOR Auditors

| | | | | |
|---|---|---|---|---|
| Are DOR auditors exempt employees? | 10,65,67 | new AS 39.25.110 | no | yes |

## Other Administrative Provisions

| | | | | |
|---|---|---|---|---|
| Monthly filings | 22, 24,25 | 0.02 | ambiguity (tried to resolve in regulations) about interaction between annual tests and credits and monthly filings | Clear and separate rules for (i) non CI, not subject to floor under (f), (ii) CI, and (iii) subject to floor under (f). |
| Penalty for Failure to Report (when no tax is due) | 47 | .030(d) | none (penalty was tied to tax being due) | up to $1,000 a day under departments regs |
| Retroactive Changes Require Payment | 50 | new .075 | Regulatory provision 15 AAC 55.200 | Incorporated into Statute |
| Electronic Payment and Filing | 51 | .110(e)& (f) | silent | DOR may require |

sections 66 & 67 are transitional rules

## Cook Inlet - no substantive change, however regs imported into statute

| | | | | |
|---|---|---|---|---|
| CI Allocation Rules | 19 - 21, 55, 59 | new .165(f)-(i) | Allocations and trying to fit all the other terms of the statute into the statutory ceiling language found in 15 AAC 55.360, 15 AAC 55.223 & 15 AAC 55.235. | adopted into statute |

## Effective Date

| | | | | |
|---|---|---|---|---|
| General Rules | 64, 69 | | | Jan 1 2008 |
| Deferred Maintenance Rules | 64 | new .165(e) (19) | | Apr 1 2006 |

Summary Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law

| Issue | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|
| **Base Rate** | *AS 43.55.011 (e) & (g)* | *Bill Sections 15 & 17* |
| Base Tax Rate | 22.50% | 25% |
| **Progressivity** | *AS 43.55.011(g) & (h)* | *Bill Sections 17,18* |
| Starting point | $40 | $30 |
| Tax/$ of Price Index | 0.25% | 0.20% |
| Average Value over | month | year |
| **Gross Value Floor** | *AS 43.55.011(f)* | *Bill Section 15, 16, 31-36, & 41-42* |
| Base | Prudhoe & Kuparuk | North Slope |
| Rate | ranges from 0% to 4% | 10% |
| Credits further reduce floor tax? | Yes | No |
| **Credits** | *AS 43.55.023 and 55.025* | *Bill Section 26-28, 38-44 & 63* |
| Investment Credits | Taken in year of investment | 1/2 in each of two years |
| Loss Carry Forward Credits | 20% | 25% |
| Transitional Investment Credits | Yes | No |
| **Exploration Credits** | *AS 43.55.025* | *Bill Section 36 - 44* |
| DNR approval required? | In CI, to avoid 3 mile limit | Always |
| Confidentiality of well data | 10 years | 2 years |
| Pre-existing well | One drilling season | Two consecutive drilling seasons |
| "DNR TIE" Credits for pre 2003 seismic work? | no | 5% |
| **Allowable Lease Expenditures** | *AS 43.55.165* | *Bill Sections 52-64* |
| Use producer audits of operators? | Yes | No |
| DR&R Allowed? | Some | No |
| Deferred Maintenance allowed? | Yes | No |
| Field Topping Plants allowed? | Yes | No |

Summary Comparison between Governor's October 1, 2007 Production Tax Proposal and Current Law

| Issue | Current Law | Governor's 10/1/2007 Proposal |
|---|---|---|
| **State Purchase of Credits** | ***AS 43.55.023(f) & (g)*** | ***Bill Section 45 (AS 43.55.028)*** |
| Paid from: | "appropriations made by law" | oil and gas credit fund, funded from production taxes |
| Annual dollar cap per taxpayer? | $25 million | none |
| **Information** | ***AS 43.05.230 and royalty statutes*** | ***Bill Sections 2-9,11-13, 49 & 61*** |
| forward looking information required | none | information "necessary to forecast ... revenues under AS 43.55". Penalty up to $1000 a day. |
| Disclosure of tax information | if aggregated to "prevent the identification of particular returns." | if aggregated w/2 other producers |
| DNR sharing royalty information w/ DOR | limited ability | expanded ability |
| DOR sharing tax information with DNR | limited ability | expanded ability |
| **Statute of Limitations** | ***AS 43.05.260*** | ***Bill Sections 1,14,50 new AS 43.55.075*** |
| State assessment must be issued within | 3 yrs | 6 yrs |
| **DOR Auditors** | ***As 39.25.100*** | ***Bill Sections 10, 65, 67*** |
| DOR auditors exempt employees? | no | yes |
| **Effective Date** | | ***Bill Section 64*** |
| Generally | | Jan 1 2008 |
| Deferred Maintenance Rules | | Apr 1 2006 |

REPORT TO THE ALASKA STATE LEGISLATURE

on the

# PRELIMINARY ESTIMATE OF THE FY 2008 REVENUE EFFECTS OF FOUR CHANGES PROPOSED BY GOVERNOR SARAH PALIN TO THE OIL AND GAS PRODUCTION TAX, AS 43.55, ON SEPTEMBER 4, 2007 AND OCTOBER 1, 2007

Dan E. Dickinson, CPA, CMA
October 3, 2007

## Executive Summary

On September 4, 2007, the Palin Administration proposed changes to Alaska's oil and gas production tax (AS 43.55). Also handed out at that time was a chart demonstrating estimated FY 2008 production tax revenues under different scenarios. That chart showed that at a price level of $70 dollars a barrel, a revenue estimate under current law and cost and volume assumptions to be roughly:

- a billion dollars higher than revenues had the ELF-based tax still been in place; however,
- a billion dollars lower than under current law and summer of 2006 cost and volume assumptions; and
- 800 million dollars lower than under the Governor's plan also using summer of 2006 cost and volume assumptions.

On October 1, 2007, the Administration made public a work draft of a bill incorporating these and other changes. This paper analyzes four of the proposed changes. If implemented for all of FY 2008, these four changes proposed by the Governor would have large and immediate revenue impacts, and in fact account for the 800 million dollar difference identified above:

> The tax rate would go from 22.5 to 25%. At currently predicted volumes and costs, that would generate a revenue increase of about 37.5 million dollars if oil is at $30 a barrel for the entire year and 342.5 million dollars if oil remains at $80 for the entire year.
>
> Progressivity – a mechanism that imposes an additional tax when net values are very high - is changed so that in most circumstances at prices greater than $55 dollars a barrel it will raise up to roughly 190 million more dollars a year than current law. However, because the Administration has opted for the administratively less complex method of calculating progressivity on an annual rather than monthly basis, in cases of short duration spikes in price the proposal may capture fewer dollars.

The TIE (Transitional Investment Expenditure) credits would be eliminated. Those credits allowed producers that are making both current investments, and had been making investments in the period 2000 through 2005, to "supercharge" their current investment credits from 20% to 30%. In FY 2008, eliminating TIE credits will increase revenue by about $190 million a year.

A fourth proposed change will likely have a large revenue impact in its first year but little impact thereafter. It will require capital credits to be taken over two years instead of in the year of investment. If the change were effective July 1, 2007, the State would receive a revenue boost of about 190 million dollars in FY 2008, but would notice little change thereafter.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

## Analysis

On September 4, 2007, the Palin Administration proposed 10 changes to Alaska's oil and gas production tax (AS 43.55) summarized in a 150 word handout. Also handed out at that time was a chart handout entitled "FY 2008 Production Tax Estimates." This chart showed FY 08 production tax revenues over a range of oil prices between $30 and $70 using the four following sets of assumptions:

(a) Current law and production and cost assumptions;
(b) Current law using production and cost assumptions from the summer of 2006;
(c) The Governor's proposed changes; and,
(d) The ELF-based tax as though it were still in place.

At a price level of $70 dollars a barrel[1], the revenue estimate shown under current law and assumptions is roughly:

- A billion dollars higher than revenues had the ELF-based tax still been in place; however,
- A billion dollars lower than under current law and summer of 2006 cost and volume assumptions; and
- 800 million dollars lower than under the Governor's plan also using summer of 2006 cost and volume assumptions.

On October 1, 2007, the Administration made a work draft of a bill public. This paper analyzes four of the proposed changes from that bill. Using a very simple one page model (Attachment One), the Governor's proposed changes are compared with existing law using the same cost and volume assumptions. If implemented for all of FY 2008, these four changes proposed by the Governor have large and immediate revenue impacts, and, in fact, account for the 800 million dollar difference identified above between current law and the proposal. The four changes are:

A change in tax rate on net profits from 22.5% to 25%;
Two of the three changes proposed for the method of calculating progressivity;
Elimination of the TIE credit, and
Requiring taxpayers to take investment credits over two years.

On September 4, 2007, when the chart was released the Commissioner of DOR stated that he did not know when the bill would become effective. However the analysis that

[1] Although on September 4, 2007, the ANS price was in the mid seventies, according to archival price data at DOR's website, it had been 70.76 as recently as August 22 (Site accessed October 2, 2007:
http://www.tax.state.ak.us/programs/oil/prices/monthlydata/2007/Aug07.xls

best fits the September 4 handouts, and that is presented in this paper is driven by a July 1, 2007, effective date. The work draft of the bill, however, has proposed a January 1, 2008, effective date. Using the effective dates in the Governor's proposed legislation would cut the 800 million difference for FY 2008 roughly in half to $400 million.

**"25% Tax Rate on Net Profits"**

AS 43.55.011(e) levies a tax of 22.5% on the "production tax value of the taxable oil and gas." The proposed change found in sections 15 and 17 of the October 1, 2007, work draft modifies AS 43.55.011(e) and (g) to up that figure by an additional 2.5% to 25%. The effect of this change on 2008 revenues is modeled on the table below.

**Simple Model of FY 2008 Production Tax Revenue: Base Rate**

| Price Scenarios on Sept 4 Handout | Annual Volumes (w/o royalty) | Total Destination Value of non Royalty Barrels | Less Downstream costs from RSB | Less Upstream costs (capex and opex) from RSB | Resulting Production Tax Value | Tax Rate | Base Tax Calculation at 22.5% and 25% and difference |
|---|---|---|---|---|---|---|---|
| $/bbl | MM bbls | MM $ | MM $ | MM $ | MM $ | % | MM $ |
| A | B | C= (A * B) | D | E | F= (C+D+E) | G | H= (F*G) |
| **Under Current Law** | | | 7.22 per bbl | | | | |
| 30 | 244 | 7,320 | (1,762) | (4,058) | 1,500 | 22.5% | 337.6 |
| 40 | 244 | 9,760 | (1,762) | (4,058) | 3,940 | 22.5% | 886.6 |
| 50 | 244 | 12,200 | (1,762) | (4,058) | 6,380 | 22.5% | 1,435.6 |
| 60 | 244 | 14,640 | (1,762) | (4,058) | 8,820 | 22.5% | 1,984.6 |
| 70 | 244 | 17,080 | (1,762) | (4,058) | 11,260 | 22.5% | 2,533.6 |
| 80 | 244 | 19,520 | (1,762) | (4,058) | 13,701 | 22.5% | 3,082.6 |
| **Under Changes Indicated in Sept 4th handouts** | | | | | | | |
| 30 | | | | | | 25.0% | 375.1 |
| 40 | | | | | | 25.0% | 985.1 |
| 50 | | | | | | 25.0% | 1,595.1 |
| 60 | | | | | | 25.0% | 2,205.1 |
| 70 | | | | | | 25.0% | 2,815.1 |
| 80 | | | | | | 25.0% | 3,425.1 |
| **Incremental Change: Proposal less Current Law** | | | | | | | |
| 30 | | | | | | | 37.5 |
| 40 | | | | | | | 98.5 |
| 50 | | | | | | | 159.5 |
| 60 | | | | | | | 220.5 |
| 70 | | | | | | | 281.5 |
| 80 | | | | | | | 342.5 |

The format of this table will be repeated several times in this report excerpting columns from the entire table which can be found as Attachment One. The table is divided into three horizontal sections. Within each section the analysis is shown at prices that range from $20 a barrel up to the today's price of $80. (Note – when comparisons are made to the Governor's chart, the analysis uses the Administration's assumptions and only goes up to $70.) The first section is based on current law. Below it, the second section is based on the Governor's September 4, 2007, proposals. Finally, the third section is just the difference between the first two sections – the incremental dollar effect of implementing the change.

Columns A through F are identical whether under current law or the proposed changes.[2] The first, column A, is the destination value. The next column has taxable barrels based on the volumes found in the Department of Revenue's spring 2007 Revenue Sources Book (RSB). Column C is the product of the first two. In the next two columns, costs also found in the RSB are deducted. In column D, downstream costs are quoted at $7.22 a barrel, which must be multiplied by volumes, while upstream costs are given as total dollars in column E. Finally, costs are subtracted to arrive at the "production tax value" shown in column F.

Starting with column G, the section under current law and the section describing the effect of the proposals are different. Current law multiplies "production tax value" times 22.5%, while in the second section the Governor's proposed rate of 25% is used. The "Incremental Change" portion of Column H shows the annual difference this proposed change would make at this year's production levels and it ranges from $37 million at the $30 per barrel price level to just under 10 times that or roughly $342.5 million dollars at the $80 price level seen today.

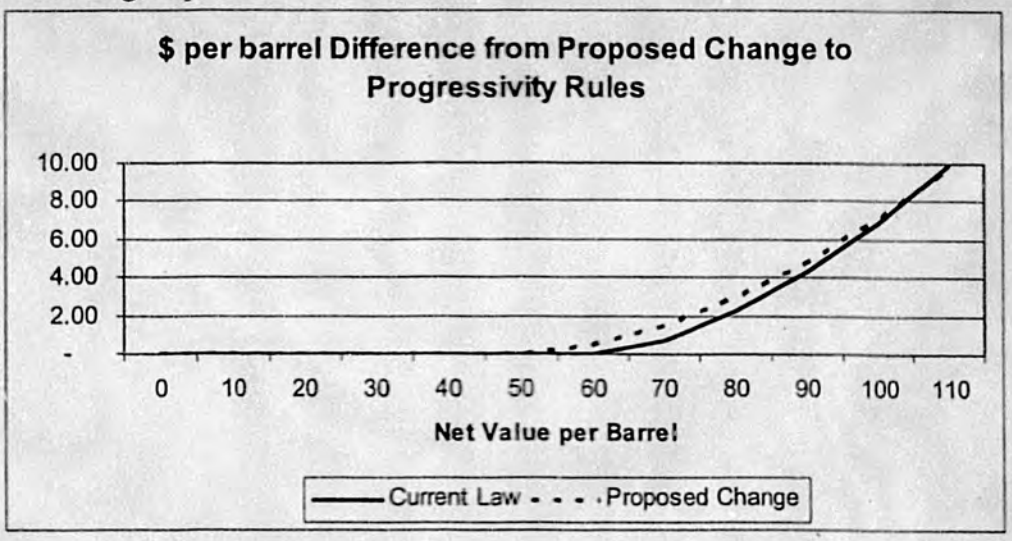
**"Progressive Feature that Kicks In at $30 Net Value (annual) and rises at Two-tenths of a Percent per Dollar"**

This proposal incorporates three changes to the progressivity feature of which two are incorporated into this model. Under current law, AS 43.55.011(g) and (h), the progressive feature is calculated as an additional tax of two and a half tenths of a percent for every dollar per barrel of net value over the $40 price index starting point. This proposal, found in sections 17 and 18 of the October 1 work draft, suggests the progressive feature should be calculated as an additional tax of two tenths of a percent for every dollar per barrel of net value over a $30 price index starting point.

[2] That is, they are identical in this simple model. The Governor has also proposed some smaller changes described below that would affect the total deductible costs as well; however, they have not been modeled here.

| | Current Law | Proposed Change |
|---|---|---|
| Price Index starting point | $40 per barrel | $30 per barrel |
| Rate per $ in Price Index | .25% | .20% |

Put more plainly, under the proposal, progressivity will start at lower per barrel values than under current law. However, once it starts, progressivity will rise more slowly. Until the net production tax value reaches $80 dollars a barrel, the Administration's suggested change to these two parameters will consistently produce more progressivity dollars than the current statute. At a net of $80, the suggested changes and current law will yield the same result.[3] At net values above $80, the formula in current law will produce more progressivity dollars.[4] However, under both the current statute and the Governor's proposal, the total tax rate progressivity is capped at 25% - which occurs at an even higher price.




As might be expected at today's high prices, changes to progressivity are an important part of calculating the overall tax burden and the difference between current law and this proposal. The table on the next page illustrates the dollar effect of these two changes in FY 2008.

This table has the same format as the table described on pages 4 and 5 above -- the table is divided into three horizontal sections for current law, the September 4, 2007, proposals, and, the difference between those two. Within each section the analysis is

[3] Because (80 - 30)*.002 = (80 – 40) *.0025 for those who care about the algebra.
[4] To translate $80 net value into WC market prices total RSB costs of $23.85 per barrel need to be added meaning the cross over point would be about $103.85, roughly 20% higher than current prices.

shown at prices that range from $20 a barrel up to the today's price of $80. The computations to reach column F are not reproduced.

Column I converts the column F production tax value back to dollars per barrel by dividing column F dollars by the barrels in column B. Column J shows the starting point for the Price Index as $40 under current law and $30 under the Governor's proposal. In Column K, the price index is calculated by subtracting J from I. In Column L, the current and proposed progressivity rates per dollar of price factor are shown as .0025% and .002% respectively. In column M, these are multiplied by the price index to yield the new progressivity rate. Finally, in column N, the dollars of progressivity are calculated by multiplying the column M rate by the same base that was subject to taxation found in column F.

**Simple Model of FY 2008 Production Tax Revenue: Progressivity**

| Price Scenarios on Sept 4 Handout | Annual Volumes (w/o royalty) | MEMO: Resulting Production Tax Value | Per Barrel Production Tax Value | Adjustment for Price Index Calculation | Price Index | Progressivity Rate per Price Index Dollar | Resulting progressivity rate | Progressivity Tax = Rate Times Value |
|---|---|---|---|---|---|---|---|---|
| $/bbl | MM bbls | MM $ | $/bbl | $/bbl | $/bbl | % | % | MM $ |
| A | B | F= (C+D+E) | I= (F/B) | J | K= (I-J) | L | M (L*K) | N= (M*F) |
| **Under Current Law** | | | | | | | | |
| 30 | 244 | 1,500 | $ 6.15 | 40.0 | | | | |
| 40 | 244 | 3,940 | $ 16.15 | 40.0 | | | | |
| 50 | 244 | 6,380 | $ 26.15 | 40.0 | | | | |
| 60 | 244 | 8,820 | $ 36.15 | 40.0 | | | | |
| 70 | 244 | 11,260 | $ 46.15 | 40.0 | $ 6.15 | 0.25% | 1.54% | 173.1 |
| 80 | 244 | 13,701 | $ 56.15 | 40.0 | $ 16.15 | 0.25% | 4.04% | 553.1 |
| **Under Changes Indicated in Sept 4th handouts** | | | | | | | | |
| 30 | | | $ 6.15 | 30.0 | | | | |
| 40 | | | $ 16.15 | 30.0 | | | | |
| 50 | | | $ 26.15 | 30.0 | | | | |
| 60 | | | $ 36.15 | 30.0 | $ 6.15 | 0.20% | 1.23% | 108.5 |
| 70 | | | $ 46.15 | 30.0 | $ 16.15 | 0.20% | 3.23% | 363.7 |
| 80 | | | $ 56.15 | 30.0 | $ 26.15 | 0.20% | 5.23% | 716.5 |
| **Incremental Change: Proposal less Current Law** | | | | | | | | |
| 30 | | | | | | | | |
| 40 | | | | | | | | |
| 50 | | | | | | | | |
| 60 | | | | (10.0) | $ 6.15 | | 1.23% | 108.5 |
| 70 | | | | (10.0) | $ 10.00 | | 1.69% | 190.6 |
| 80 | | | | (10.0) | $ 10.00 | | 1.19% | 163.4 |

When just these two elements are considered, the Governor's proposal can be seen to yield between $108.5 and $190.6 million more than the current rules at prices of $60 or above. (With this set of inputs the maximum difference is close to $190.6 million.)

However, what these two elements take in higher revenues, a third part of this proposed change may more than give back. To many people in the Legislature in 2006, the purpose of the progressivity was to capture a premium when there were price spikes. Therefore, current law requires the analysis to be done on a monthly basis. (Although now as daily prices hover around the $80 per barrel level it may seem quaint; but in the summer of 2006 as the current law was being crafted, prices were surpassing $70 a barrel for the first time and to many that seemed like a spike.) The Administration's proposal would be administratively simpler requiring only an annual analysis. However, this change might reduce taxes by hundreds of millions of dollars.

Consider the price spike preceding the first Gulf War when prices doubled between July and September 1991, and then soon returned to where they had been. The following table illustrates what might happen should FY 2008 have just such a spike in it:

**Comparing Annual and Monthly analysis of FY 2008 with hypothetical spike**

| | US West Coast Price/ bbl | Per Barrel Total Costs | Per Barrel Production Tax Value | Adjustment Converting Production Tax Value to Price Index | Price Index | Rate per Dollar of Price Factor | Incre-mental Progres-sivity % | Volumes (millions of bbls) | Progres-sivity Tax (millions of dollars) |
|---|---|---|---|---|---|---|---|---|---|
| | $/bbl | $/bbl | $/bbl | $/bbl | $/bbl | % | % | MM bbls | MM $ |
| A | B | C | D= (B+C) | E | F= (D+E) | G | H= (F*G) | I | J= (D*H*I) |
| **Monthly Analysis, $40 Adjustment and .0025% Parameter under Current Law** | | | | | | | | | |
| Jul | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.7 | - |
| Aug | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.7 | - |
| Sep | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.1 | - |
| Oct | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.7 | - |
| Nov | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.1 | - |
| Dec | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.7 | - |
| Jan | 77.15 | (23.85) | 53.29 | (40.00) | 13.29 | 0.25% | 3.32% | 20.7 | 36.7 |
| Feb | 102.86 | (23.85) | 79.01 | (40.00) | 39.01 | 0.25% | 9.75% | 18.7 | 144.2 |
| Mar | 77.15 | (23.85) | 53.29 | (40.00) | 13.29 | 0.25% | 3.32% | 20.7 | 36.7 |
| Apr | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.1 | - |
| May | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.7 | - |
| Jun | 51.43 | (23.85) | 27.58 | (40.00) | - | 0.25% | 0.00% | 20.1 | - |
| | | | | | | | | 244.0 | 217.6 |
| **Yearly Analysis, $30 Adjustment and .002% Parameter, as Proposed** | | | | | | | | | |
| Yr | 60.00 | (23.85) | 36.15 | (30.00) | 6.15 | 0.20% | 1.23% | 244.0 | 108.5 |

In the simple model presented on page 7, no progressivity dollars were generated under current law at the $60 scenario level. Implicit in the model is that the price stays flat at $60 all year. But, in the model presented on page 8, instead of a flat $60, the price hovers around $51.43 for most of the year except for a three month spike[5]. In this hypothetical spike, like in 1991, prices will double over two months and then fall back. The $51.43 was chosen so that the year's price would average out to $60 -- and the point would be dramatically illustrated. Under this scenario, the current law would generate $217.6 million of progressivity over the year – just about twice what would be generated under the rules the Governor is proposing. (The $108.5 figure under the Administration's plan can be found in both the tables on page 7 and 8.)

Please note the table on page 8 is not a forecast but an illustration!!! If prices stay relatively flat, incorporating the kind of variation seen in most 12 month periods, the Governor's proposal will produce more progressivity dollars than current law. However, it will not necessarily catch a single peak or spike. Incidentally, as might be expected, if the Governor's two suggested parameter changes are combined with a monthly analysis, then a spike such as that illustrated in the table on page 8 brings in significantly more revenue than current law.

**"Eliminates the Transitional Investment Expenditures (TIE) Credits"**

The Transitional Investment Expenditures (TIE) credit, AS 43.55.023 (i), was transformed in the Legislative process. As originally introduced by the Murkowski Administration, it permitted capital costs incurred in the prior five years to be used as additional capital credits through 2013 with certain restrictions. The Legislature transformed the idea and required new matching investment before the TIE credits would be allowed. If a producer were in harvest mode and not making any new investments, the TIE would be of no use, whereas a producer that increased its investment by about 40% could take full advantage of the TIE credit. The law allowed certain producers with a good history of investment to "supercharge" their new investments made between 2006 and 2012 and to boost their credit for that investment by an additional 10% from 20% to an effective rate of 30%. To take advantage of this 10% credit, a producer had to have two things – prior investment and current investment. The credit would have expired in 2013 on its own. The Palin Administration, in section 63 of the October 1, 2007, work draft, proposes ending it sooner – December 31, 2007 -- which means that TIE credits would still be allowed for half of FY 2008. However, for simple modeling purposes to best match the Administration's September 4, 2007, model, the elimination of the TIE credit is shown for the entire year.

The simple model incorporates the following assumptions. In its August 3, 2007, Petroleum Profits Tax (PPT) Implementation Status Report, the DOR estimates that $1.9

[5] Of all the places in the future to place the spoke, February was chosen with only 29 days of production in FY 2008 to model a conservative scenario.

billion in capital costs will be reported for FY 2008. The model further assumed that in the second year of the TIE program, every dollar invested in FY 2008 still has a match from prior years' investments – that is, all the investment was supercharged from 20% to 30%. Thus, current law allows, and the Governor's proposal will disallow, 10% of $1,900 million or $190 million a year regardless of the price of oil. In the table below, column E is a memo column that shows total upstream costs, columns H and N were calculated in previous tables, and column O sums those results together to generate total tax before credits. In column P, under current law, a credit of 10% of 1.9 billion dollars is taken; no credit is allowed under the Governor's proposal. The final column shows the effect of applying the credit in column P against the tax in column O.

**Simple Model of FY 2008 Production Tax Revenue: TIE**

| Price Scenarios on Sept 4 Handout | MEMO: Less Upstream costs (capex and opex) from RSB | MEMO: Base Tax Calculation at 22.5% and 25% and difference | MEMO: Progressivity Dollars | Total Taxes before credits | TIE Credits | Taxes Due after application of TIE Credit |
|---|---|---|---|---|---|---|
| $/bbl | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ |
| A | E | H | N | O= (H+N) | P | |
| **Under Current Law** | | | | | | |
| 30 | (4,058.0) | 337.6 | | 337.6 | (190.0) | 147.6 |
| 40 | (4,058.0) | 886.6 | | 886.6 | (190.0) | 696.6 |
| 50 | (4,058.0) | 1,435.6 | | 1,435.6 | (190.0) | 1,245.6 |
| 60 | (4,058.0) | 1,984.6 | | 1,984.6 | (190.0) | 1,794.6 |
| 70 | (4,058.0) | 2,533.6 | 173.1 | 2,706.7 | (190.0) | 2,516.7 |
| 80 | (4,058.0) | 3,082.6 | 553.1 | 3,635.7 | (190.0) | 3,445.7 |
| **Under Changes Indicated in Sept 4th handouts** | | | | | | |
| 30 | | 375.1 | | 375.1 | | 375.1 |
| 40 | | 985.1 | | 985.1 | | 985.1 |
| 50 | | 1,595.1 | | 1,595.1 | | 1,595.1 |
| 60 | | 2,205.1 | 108.5 | 2,313.6 | | 2,313.6 |
| 70 | | 2,815.1 | 363.7 | 3,178.8 | | 3,178.8 |
| 80 | | 3,425.1 | 716.5 | 4,141.6 | | 4,141.6 |
| **Incremental Change: Proposal less Current Law** | | | | | | |
| 30 | | 37.5 | | 37.5 | 190.0 | 227.5 |
| 40 | | 98.5 | | 98.5 | 190.0 | 288.5 |
| 50 | | 159.5 | | 159.5 | 190.0 | 349.5 |
| 60 | | 220.5 | 108.5 | 329.0 | 190.0 | 519.0 |
| 70 | | 281.5 | 190.6 | 472.1 | 190.0 | 662.1 |
| 80 | | 342.5 | 163.4 | 505.9 | 190.0 | 695.9 |

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

**"Requires Capital Expenditure Costs to be Taken as Credits over Two Years Rather than Immediately"**

Under current law, AS 43.55.023 (a), capital investment credits may be taken in the year the investment is made. The proposal, found in section 26 of the October 1, 2007, work draft, will require that for a credit generated in year one, only half can be applied in year one and the rest in year two. In DOR Commissioner Galvin's oral presentation September 4, 2007, he stressed that this change was intended to make annual revenues more stable and predictable. There will, however, be immediate one-year revenue implications and the model below assumes the effective date of the change in the law would be timed so as to maximize the revenue effect on FY 2008.

However, this large revenue effect will essentially be limited to one year. In the next year, the total credits allowed will be half of that year's investment and half of the investment made the year after that and so forth each year forward. If investment stays roughly constant, in subsequent years there will be no revenue effect. Thus from the point of view of the State, this appears to create first year savings only. From the taxpayers' point of view, the value of the credits essentially falls by one half year's time value of money.

In the simple model on page 12, columns E, H, N & O are as they were in the TIE table. In column Q, FY 2008 current law will allow 20% of $1,900 or $380 million a year. The Governor's proposal will disallow half of that, 10% of $1,900 or $190 million, and allow the other half. Again, this is regardless of the price of oil. In the final column of the table, this amount is subtracted from the taxes derived in the prior two sections.

This model assumes that the tax and forecasting are on the same basis; but, the world is not that simple. The tax system is based on the calendar year, while the fiscal year (FY) runs from July 1 to June 30. Thus the effect of this change on fiscal year revenues will be split between two fiscal years (FY 2008 and 2009) but thereafter will have little revenue effect.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
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**Simple Model of FY 2008 Production Tax Revenue: Cap Credit**

| Price Scenarios on Sept 4 Handout | MEMO: Less Upstream costs (capex and opex) from RSB | MEMO: Base Tax Calculation at 22.5% and 25% and difference | MEMO: Progressivity Dollars | Total Taxes before credits | First Year Capital Investment Credit (full or half) | Taxes Due after application of Capital Investment Credit |
|---|---|---|---|---|---|---|
| $/bbl | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ |
| A | E | H | N | O= (H+N) | Q | |
| **Under Current Law** | | | | | | |
| | | | | | 1,900.0 | |
| 30 | (4,058.0) | 337.6 | | 337.6 | (380.0) | (42.4) |
| 40 | (4,058.0) | 886.6 | | 886.6 | (380.0) | 506.6 |
| 50 | (4,058.0) | 1,435.6 | | 1,435.6 | (380.0) | 1,055.6 |
| 60 | (4,058.0) | 1,984.6 | | 1,984.6 | (380.0) | 1,604.6 |
| 70 | (4,058.0) | 2,533.6 | 173.1 | 2,706.7 | (380.0) | 2,326.7 |
| 80 | (4,058.0) | 3,082.6 | 553.1 | 3,635.7 | (380.0) | 3,255.7 |
| **Under Changes Indicated in Sept 4th handouts** | | | | | | |
| 30 | | 375.1 | | 375.1 | (190.0) | 185.1 |
| 40 | | 985.1 | | 985.1 | (190.0) | 795.1 |
| 50 | | 1,595.1 | | 1,595.1 | (190.0) | 1,405.1 |
| 60 | | 2,205.1 | 108.5 | 2,313.6 | (190.0) | 2,123.6 |
| 70 | | 2,815.1 | 363.7 | 3,178.8 | (190.0) | 2,988.8 |
| 80 | | 3,425.1 | 716.5 | 4,141.6 | (190.0) | 3,951.6 |
| **Incremental Change: Proposal less Current Law** | | | | | | |
| 30 | | 37.5 | | 37.5 | 190.0 | 227.5 |
| 40 | | 98.5 | | 98.5 | 190.0 | 288.5 |
| 50 | | 159.5 | | 159.5 | 190.0 | 349.5 |
| 60 | | 220.5 | 108.5 | 329.0 | 190.0 | 519.0 |
| 70 | | 281.5 | 190.6 | 472.1 | 190.0 | 662.1 |
| 80 | | 342.5 | 163.4 | 505.9 | 190.0 | 695.9 |

The table on the next page sums up the results of the four tables presented previously to show the amount of revenue, and revenue differences, accounted for by this simplistic accounting. Column H and N are summed in column O to show total tax before credits. Columns P and Q are the two credits discussed; and, the final result of applying the credits is seen in Column R.

To determine the Administration's estimates under current law and under the Governor's proposal, figures were simply extrapolated off the September 4, 2007, handout table and these are shown in column S. The sole purpose of making this comparison is to suggest that simplistic models of the four items yield most, but not all, of the revenue differences.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

## Simple Models of FY 2008 Production Tax Revenue: Summary

Dollar figures in millions (except when per barrel)

| Price Scenarios on Sept 4 Handout | Base Tax Calculation at 22.5% and 25% and difference | Progressivity Tax = Rate times value | Total Tax before credits | TIE Credits (Transitional Investment Expenditures) | Capital Costs * 20% or .10% | Tax net of credits | Tax per Price Scenarios on Sept 4 Handout | Unaccounted for in this simple model | Unaccounted for in this simple model (%) |
|---|---|---|---|---|---|---|---|---|---|
| $/bbl | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ | % |
| A | H= (F*G) | N= (M*F) | O= (H+N) | P= (Q/2) | Q= | R= (O+P+Q) | S | T (S-R) | U= (T/S) |
| **Under Current Law** | | | | | Total Cost: 1,900.0 | | | | |
| 30 | 337.6 | | 337.6 | (190.0) | (380.0) | - | - | | |
| 40 | 886.6 | | 886.6 | (190.0) | (380.0) | 316.6 | 200 | (116.6) | -58% |
| 50 | 1,435.6 | | 1,435.6 | (190.0) | (380.0) | 865.6 | 700 | (165.6) | -24% |
| 60 | 1,984.6 | | 1,984.6 | (190.0) | (380.0) | 1,414.6 | 1,300 | (114.6) | -9% |
| 70 | 2,533.6 | 173.1 | 2,706.7 | (190.0) | (380.0) | 2,136.7 | 2,000 | (136.7) | -7% |
| 80 | 3,082.6 | 553.1 | 3,635.7 | (190.0) | (380.0) | 3,065.7 | | | |
| **Under Changes indicated in Sept 4th Handouts** | | | | | | | | | |
| 30 | 375.1 | | 375.1 | | (190.0) | 185.1 | 200 | 14.9 | 7% |
| 40 | 985.1 | | 985.1 | | (190.0) | 795.1 | 800 | 4.9 | 1% |
| 50 | 1,595.1 | | 1,595.1 | | (190.0) | 1,405.1 | 1,300 | (105.1) | -8% |
| 60 | 2,205.1 | 108.5 | 2,313.6 | | (190.0) | 2,123.6 | 2,000 | (123.6) | -6% |
| 70 | 2,815.1 | 363.7 | 3,178.8 | | (190.0) | 2,988.8 | 2,800 | (88.8) | -3% |
| 80 | 3,425.1 | 716.5 | 4,141.6 | | (190.0) | 3,951.6 | | | |
| **Incremental Change: Proposal less Current Law** | | | | | | | | | |
| 30 | 37.5 | | 37.5 | 190.0 | 190.0 | 185.1 | 200 | 14.9 | 7% |
| 40 | 98.5 | | 98.5 | 190.0 | 190.0 | 478.5 | 600 | 121.5 | 20% |
| 50 | 159.5 | | 159.5 | 190.0 | 190.0 | 539.5 | 600 | 60.5 | 10% |
| 60 | 220.5 | 108.5 | 329.0 | 190.0 | 190.0 | 709.0 | 700 | (9.0) | -1% |
| 70 | 281.5 | 190.6 | 472.1 | 190.0 | 190.0 | 852.1 | 800 | 47.9 | 5% |
| 80 | 342.5 | 163.4 | 505.9 | 190.0 | 190.0 | 885.9 | | | |

There are many other bells and whistles in the existing law, and their effect on individual taxpayers, or even on the totals, should not be trivialized. However, these numbers suggest, at least at this simple level of analysis, that the four items quantified in this report account for a great deal of the FY 2008 revenue change the Administration suggests will flow from their changes.

## Attachment One: Simplistic Revenue Model

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

**General Calculation:**
A: The 5 price scenarios shown in the September 4, 2007, handouts
B: Annual taxable volumes taken from the RSB, where the forecast is for 764,000 barrels a day. This is multiplied by 365 to convert to an annual number and .875 to remove royalty barrels (estimated at 12.5%) to yield 244 million taxable barrels a year.
C: The total value (of non royalty barrels) at destination is the product of price multiplied by taxable volume.
D: The estimate of 7.22 for downstream costs for FY 2008 is taken from the RSB, Table B-2b "Nominal Netback Costs- Forecast." This is multiplied times volumes for a total downstream cost of $1.762 billion.
E: Upstream costs are listed at page 16 of the RSB executive summary as $4,058.3 million.
F: The resulting production tax value is calculated at each price level by subtracting costs from destination value.

At this point, every calculation is done under existing law, then in accordance with the changes in the September 4, 2007, handouts, and, finally, the former is subtracted from the latter.

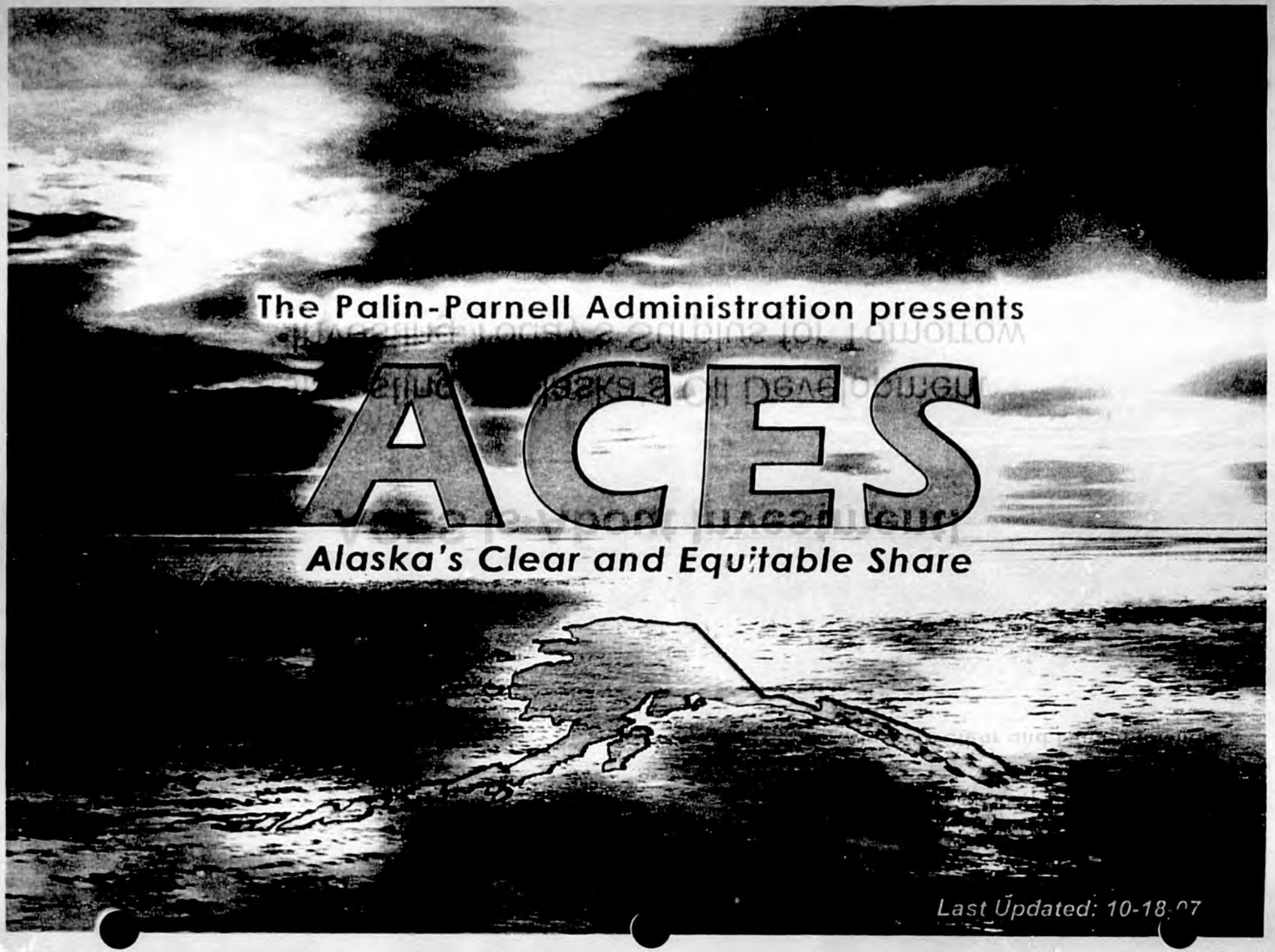
**Base Rate:**
G: Current law at 22.5% or proposal at 25%
H: Production tax value is multiplied by either 22.5% or 25%

**Progressivity:**
I: The Production Tax Value is divided through by taxable barrels to generate a per barrel value (Note: same calculation for existing law and proposed changes.)
J: Used to derive the Price Index Calculation. Either $40 or $30.
K: The Price Index is calculated where the per barrel value less the factor is positive.
L: The progressivity rate of .0025 or .002 per dollar of Price Index.
M: Price Index times progressivity rate.
N: This rate is then multiplied by the same Production Tax Value (as for the base rate.)
O. The total tax before credits is the sum of the base rate and the progressivity.
P. The TIE is calculated as 10% of the capital investments or as zero.
Q. Capital Investment credit calculated as 10 or 20% of capital investment (from DOR Petroleum Profits Tax (PPT) Implementation Report (August 3, 2007)
R. The two credits are then subtracted from the tax to arrive at the tax net of credits.
S. Tax extrapolated from the DOR handouts, rounded to the nearest 100 million dollars.
T. The difference between the DOR model and my simple build-up is the amount not accounted by the simple build-up.
U. This difference is also measured as a percent.

Preliminary Estimate of Four Proposed Changes on FY 2008 Revenues
Dan E. Dickinson
October 3, 2007

## Simple Model of FY 2008 Production Tax Revenue to match Administrations Sept 4th Handouts:

| | | | | | | Base Tax | | | Progressivity | | | | | | | Credits | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Price Scenarios on Sept 4 Handout | Annual Volumes (w/o royalty) | Total Destination Value of Royalty Barrels | Less Downstream costs from RSB | Less Upstream costs (capex and opex) from RSB | Resulting Production Tax Value | Tax Rate | Base Tax Calculation at 22.5% and 25% and difference | Per Barrel Production Tax Value | Adjustment for Price Index Calculation | Price Index | Progressivity Rate per Price Index Dollar | Resulting progressivity rate | Progressivity Tax = Rate times value | Total Tax before credits | TIE Credits (Transitional Investment Expenditures) | Capital Costs * 20% or .10% | Tax net of credits | Tax per Price Scenarios on Sept 4 Handout | Unaccounted for in this simple model | Unaccounted for in this simple model (%) |
| $/bbl | MM bbls | MM $ | MM $ | MM $ | MM $ | % | MM $ | $/bbl | $/bbl | $/bbl | % | % | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ | MM $ | % |
| A | B | C= (A * B) | D | E | F= (C+D+E) | G | H= (F*G) | I= (F/B) | J | K= (I-J) | L | M= (K*L) | N= (M*F) | O= (H+N) | P= (Q/2) | Q= | R= (O+P+Q) | S | T (S-R) | U= (T/S) |
| **Under Current Law** | | | | | | | | | | | | | | | | Total Cost: 1,900.0 | | | | |
| | | Per bbl: | (7.22) | | | | | | | | | | | | | | | | | |
| 30 | 244 | 7,320 | (1,762) | (4,058) | 1,500 | 22.5% | 337.6 | 6.15 | 40.00 | | | | | 337.6 | (190.0) | (380.0) | - | - | | |
| 40 | 244 | 9,760 | (1,762) | (4,058) | 3,940 | 22.5% | 886.6 | 16.15 | 40.00 | | | | | 886.6 | (190.0) | (380.0) | 316.6 | 200 | (116.6) | -58% |
| 50 | 244 | 12,200 | (1,762) | (4,058) | 6,380 | 22.5% | 1,435.6 | 26.15 | 40.00 | | | | | 1,435.6 | (190.0) | (380.0) | 865.6 | 700 | (165.6) | -24% |
| 60 | 244 | 14,640 | (1,762) | (4,058) | 8,820 | 22.5% | 1,984.6 | 36.15 | 40.00 | | | | | 1,984.6 | (190.0) | (380.0) | 1,414.6 | 1,300 | (114.6) | -9% |
| 70 | 244 | 17,080 | (1,762) | (4,058) | 11,260 | 22.5% | 2,533.6 | 46.15 | 40.00 | 6.15 | 0.25% | 1.54% | 173.1 | 2,706.7 | (190.0) | (380.0) | 2,136.7 | 2,000 | (136.7) | -7% |
| 80 | 244 | 19,520 | (1,762) | (4,058) | 13,701 | 22.5% | 3,082.6 | 56.15 | 40.00 | 16.15 | 0.25% | 4.04% | 553.1 | 3,635.7 | (190.0) | (380.0) | 3,065.7 | | | |
| **Under Changes indicated in Sept 4th Handouts** | | | | | | | | | | | | | | | | | | | | |
| 30 | | | | | | 25.0% | 375.1 | 6.15 | 30.00 | | | | | 375.1 | | (190.0) | 185.1 | 200 | 14.9 | 7% |
| 40 | | | | | | 25.0% | 985.1 | 16.15 | 30.00 | | | | | 985.1 | | (190.0) | 795.1 | 800 | 4.9 | 1% |
| 50 | | | | | | 25.0% | 1,595.1 | 26.15 | 30.00 | | | | | 1,595.1 | | (190.0) | 1,405.1 | 1,300 | (105.1) | -8% |
| 60 | | | | | | 25.0% | 2,205.1 | 36.15 | 30.00 | 6.15 | 0.20% | 1.23% | 108.5 | 2,313.6 | | (190.0) | 2,123.6 | 2,000 | (123.6) | -6% |
| 70 | | | | | | 25.0% | 2,815.1 | 46.15 | 30.00 | 16.15 | 0.20% | 3.23% | 363.7 | 3,178.8 | | (190.0) | 2,988.8 | 2,800 | (188.8) | -7% |
| 80 | | | | | | 25.0% | 3,425.1 | 56.15 | 30.00 | 26.15 | 0.20% | 5.23% | 716.5 | 4,141.6 | | (190.0) | 3,951.6 | | | |
| **Incremental Change: Proposal less Current Law** | | | | | | | | | | | | | | | | | | | | |
| 30 | | | | | | | 37.5 | | | | | | | 37.5 | 190.0 | 190.0 | 185.1 | 200 | 14.9 | 7% |
| 40 | | | | | | | 98.5 | | | | | | | 98.5 | 190.0 | 190.0 | 478.5 | 600 | 121.5 | 20% |
| 50 | | | | | | | 159.5 | | | | | | | 159.5 | 190.0 | 190.0 | 539.5 | 600 | 60.5 | 10% |
| 60 | | | | | | | 220.5 | | (10.00) | 6.15 | | 1.23% | 108.5 | 329.0 | 190.0 | 190.0 | 709.0 | 700 | (9.0) | -1% |
| 70 | | | | | | | 281.5 | | (10.00) | 10.00 | | 1.69% | 190.6 | 472.1 | 190.0 | 190.0 | 852.1 | 800 | (52.1) | -7% |
| 80 | | | | | | | 342.5 | | (10.00) | 10.00 | | 1.19% | 163.4 | 505.9 | 190.0 | 190.0 | 885.9 | | | |


The Palin-Parnell Administration presents
ACES
Alaska's Clear and Equitable Share
Last Updated: 10-18-07

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# ACES Is About Investment!

- Investing in Alaska's Oil Development
- Investing Today's Surplus for Tomorrow

# Alaska As Investor in Oil Development

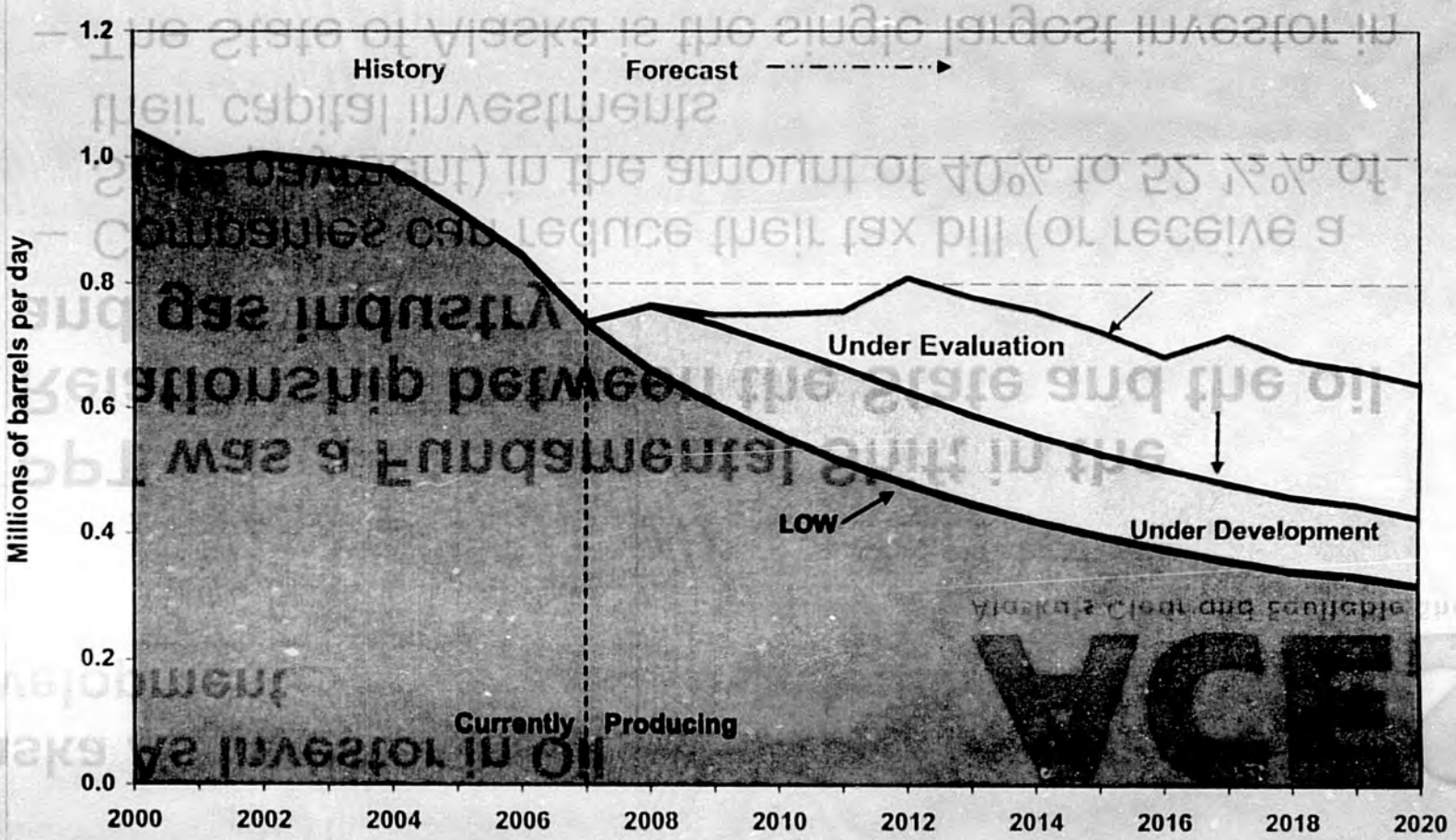
ACES
Alaska's Clear and Equitable Share

- **PPT was a Fundamental Shift in the Relationship between the State and the oil and gas industry**
  - Companies can reduce their tax bill (or receive a State payment) in the amount of 40% to 52 ½% of their capital investments
  - The State of Alaska is the single largest investor in new projects on the North Slope
  - The State is sharing the risks associated with whether these investment decisions pan out

# ANS Production Forecast
(Spring 2007)

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Alaska's Clear and Equitable Share

## Historical and Forecasted ANS Production Scenarios
## FY 2000 to FY 2020



## Investing Today's Surplus for Tomorrow

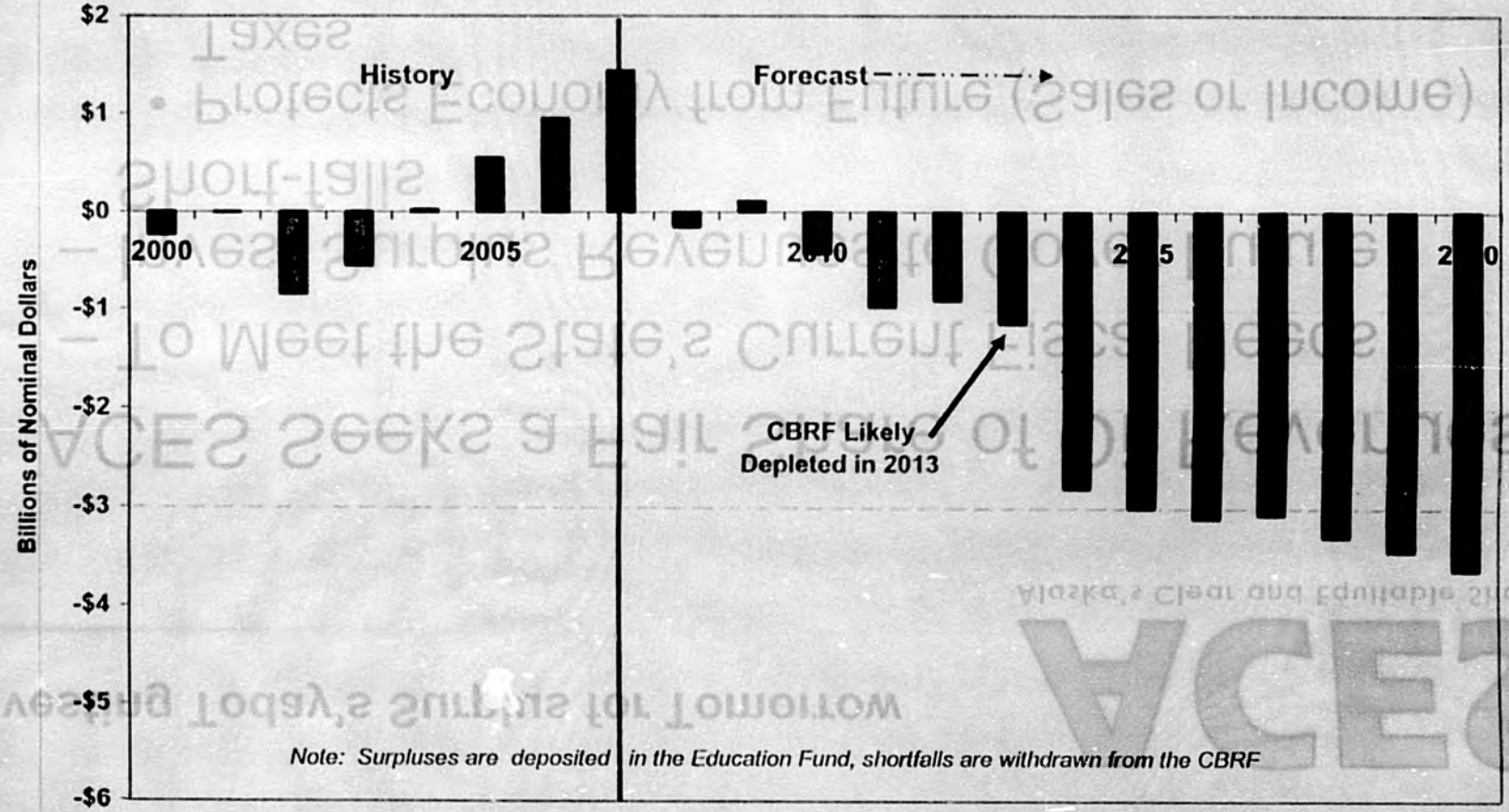
**ACES**
Alaska's Clear and Equitable Share

- ACES Seeks a Fair Share of Oil Revenues
  - To Meet the State's Current Fiscal Needs
  - Invest Surplus Revenues to Cover Future Short-falls
    - Protects Economy from Future (Sales or Income) Taxes
    - Provides Stability for Diversification of Alaska's Economy

# State Budget Forecast
(Spring 2007)

ACES
Equitable Share

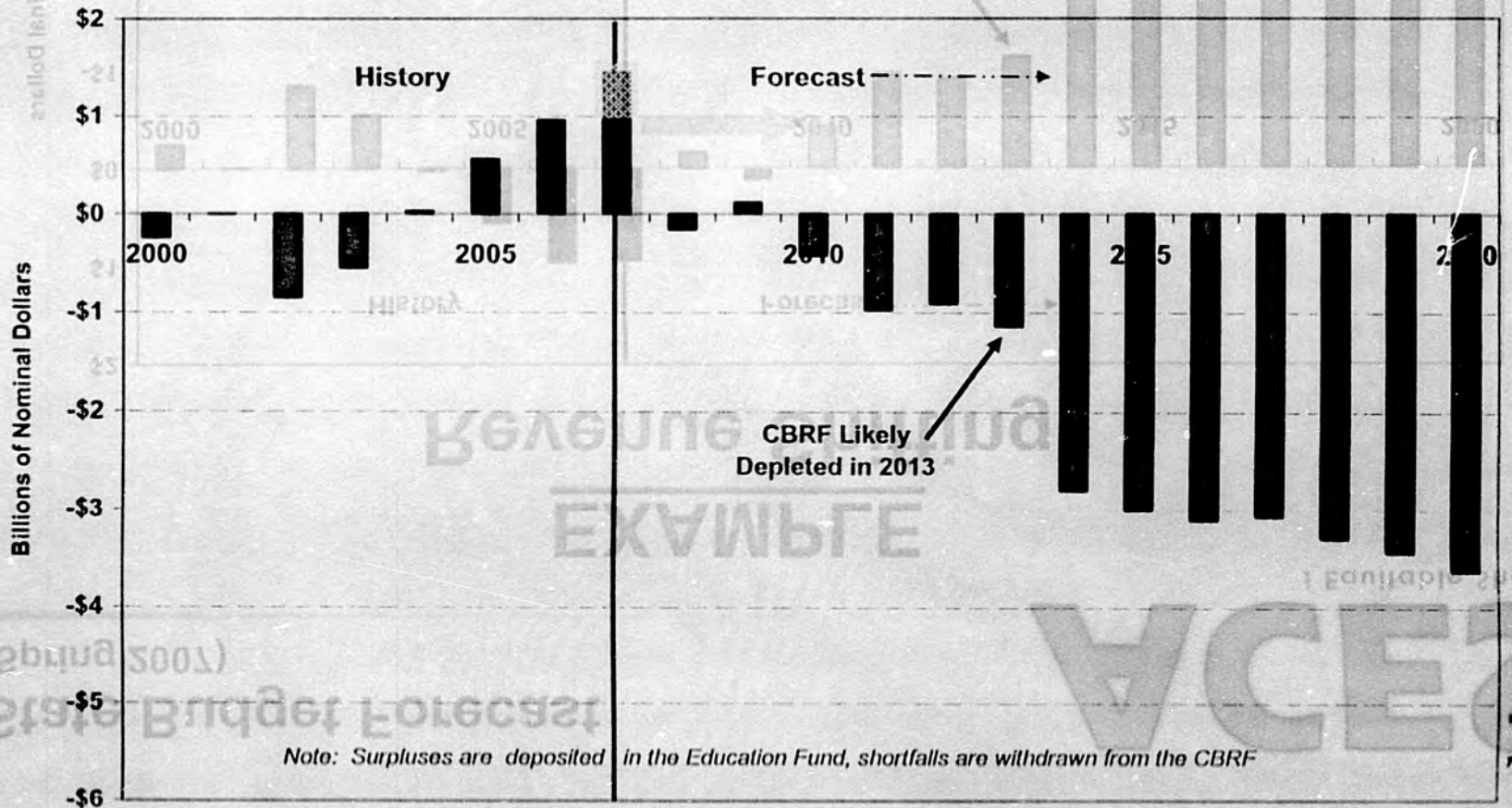
## EXAMPLE
## Revenue Shifting



# State Budget Forecast
(Spring 2007)

ACES
Equitable Share

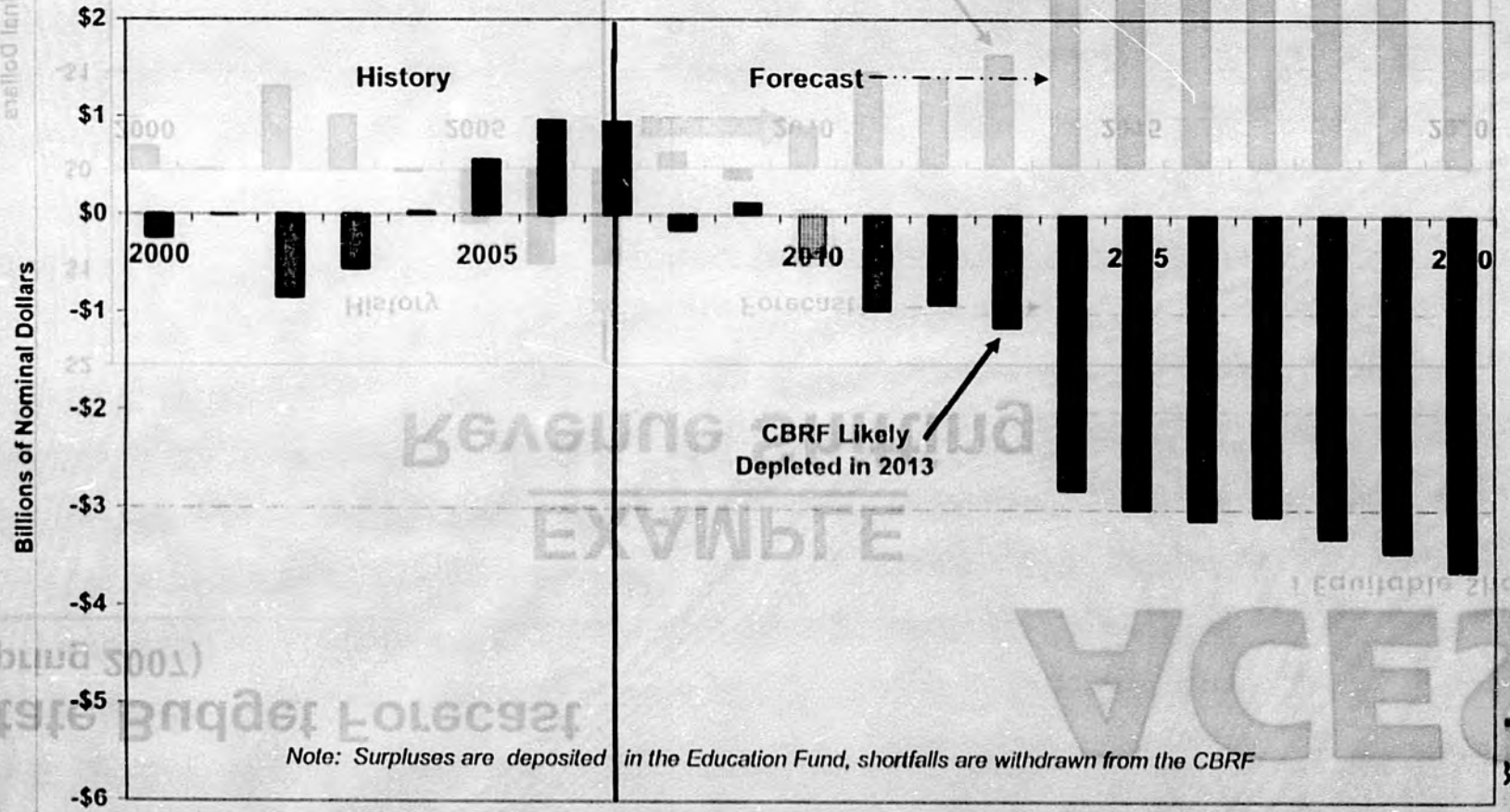
## EXAMPLE
## Revenue Shifting



# State Budget Forecast
(Spring 2007)

ACES
Equitable Share

## EXAMPLE
## Revenue Shifting



# Balancing Investment Goals

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- ACES Balances Our Investment Goals
  - Preserves Investment Climate for Oil Development Projects
  - Achieves a Fair Share of Oil Revenues to Maximize Investment in Alaska's Economic Future

# Three Days – Three Modules

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**Friday:** Tools to Protect the State

- Information, Auditors, Lease Expenditures, Credit Adjustments

**Saturday:** Global Competitiveness

- Global Tax Systems, Government Take Measurements and Models, Global Investment Factors, Country Case Studies

**Sunday:** Investment Climate & Sectional

- Oil Field Economic Models, Cost Story, Tax System Economic "Knobs", Exploration Incentives, ACES Sectional Overview

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# Tools to Protect the State

## Tools to Protect the State

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- **Information**
  - Data Collection
  - Usability
  - Public disclosure
- **Auditors**
- **Lease expenditures**
  - Definitions
  - Exclusions
- **Credit Adjustments**

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# Information

## Reporting, Use and Sharing

## Information Reporting

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**PPT provides for minimal reporting of information, primarily on annual basis**

- Reporting is not commensurate with other world-wide net-tax jurisdictions
- Makes it difficult for state to understand and respond to dynamic industry needs
- Leads to delay and conflict with taxpayers

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# ACES Requires Reporting

- Annual statement must be filed by all producers and explorers regardless of whether a tax payment is due
- Expands the list of specific information requirements for returns
- Explorers and producers that have lease expenditures or credits but no production must file with the department, all relevant expenditures, adjustments and credits

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## Clarifies DOR Authority

- Clarifies that DOR may require a producer, explorer or operator to file monthly reports with information necessary to administer the tax
- ACES provides DOR explicit authority to require producers, explorers and operators to file reports or records needed to forecast state revenue.

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# Filing Format

- Information currently filed with department is extremely variable and inconsistent. ACES would allow DOR to require electronic filing in a form compatible with the department's information management database

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## Information Management Database

- Electronic reporting form would feed into database where information would be readily available and usable for regulatory purposes, including auditing, forecasting, responding to inquiries, and generating reports
- Will accommodate ELF-based data and will be integrated with the division's accounting systems
- Will collect on volumes, wells and production, and will include profit-based data, including tracking credits, required under ACES.

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## DOR – DNR Information Sharing

- Clarifies DOR authority to share with DNR information contained in tax returns; maintains DOR confidentiality requirements under current law.
- Clarifies DNR authority to share with DOR oil and gas leasing information; maintains DNR confidentiality requirements under current law.
- Allows each agency to be fully informed and be more responsive to dynamic industry needs; helps to facilitate informed policy making and analysis

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## Guideline Interpretation

- Gives DOR express authority to issue advisory bulletins for information and guidance to producers, explorers and other interested person concerning DOR's interpretation of production tax statutes and regulations.

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## Statute of Limitations

- Period within which tax must be assessed is extended from 3 to 6 years from date of filing tax return

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# Public Disclosure

- Expressly allows publication of oil or gas production, production taxes, effective tax rates, gross value at the point of production, transportation costs for oil or gas, qualified capital expenditures, production tax values, lease expenditures and adjustments to them, and tax credits.
- Information must be aggregated among at least three taxpayers; this is similar to the rule applied in other Alaska tax areas.

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# Information Reporting Standards in Other Countries

## Gaffney Cline

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# Auditors

## Auditors

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- **Currently authorized auditor positions**
  - 18 O&G production tax auditors (Includes 1 Supervisor and 1 O&G Specialist) (DOR)
  - 7 royalty auditor positions (DNR)
- **Currently vacant auditor positions**
  - 5 DOR O&G Auditors
  - 2 DNR royalty auditors

## Auditors

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- State has been unable to recruit and retain enough qualified oil and gas auditors
- Employee classification system does not allow for targeted pay increases

## Auditors

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- ACES creates exempt class of Oil and Gas Tax and Royalty auditors
  - Allows DOR to recruit high-level, industry experienced auditors to manage the state production tax audit section
  - Current auditors would have the option of remaining with union or moving to exempt status
  - Allows the state to offer competitive salaries to retain qualified and experienced auditors

## Auditors

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- **Contract Auditors**
  - ACES also provides funding for contract auditors over the next 4 years to perform special projects, help create audit systems and train new auditors.

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# Lease Expenditures

# Lease Expenditures

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## Regulatory Definitions

- PPT sets general categories of allowable deductions with specific <u>exclusions</u>
  - Leads to lack of clarity and conflict with taxpayers
- ACES allows clarification through specific regulatory <u>inclusion</u>
  - Clarifies department's authority to set forth allowable costs
  - Avoids misunderstanding over what lease expenditures are allowable

## Lease Expenditures

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### Repeals

- Provisions allowing the department to substitute cost billings under unit operating agreements in place of general standards for allowing lease expenditures
  - 43.55.165(c) and (d)

## Lease Expenditures

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### Exclusions

- Disallows deduction of costs incurred for repair, replacement, or deferred maintenance of facilities and equipment, other than a well, that results in, or is undertaken in response to, an event that results in an unscheduled interruption in production or a release of oil or gas.
  - Encourages proactive maintenance
  - Does not apply to "Acts of God"

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Alaska's Clear and Equitable Share

## Exclusions

- Clarifies that costs to construct, acquire or operate a refinery or crude oil topping plant are not deductable.
  - Can still deduct, as an operating expense, the cost of diesel used for production

ACES
Alaska's Clear and Equitable Share

## Exclusions

- Disallows deduction of Dismantlement Removal and Restoration (DR&R) expenses
  - DR&R must be done to the satisfaction of the DNR commissioner, a subsidy of DR&R costs creates a potential conflict of state goals.
  - PPT only excluded DR&R expenses attributable to production occurring before April 1, 2006.

ACES
Alaska's Clear and Equitable Share

## Exclusions

- Disallows tax-exempt entities from obtaining transferable credit certificates under AS 43.55.023, and from transferring production tax credit certificates under AS 43.55.025

ACES
Alaska's Clear and Equitable Share

# Credit Adjustments

## Credit Adjustments

ACES
Alaska's Clear and Equitable Share

- Eliminates Transitional Investment Expenditure (TIE) Credits
  - Credits are based on expenditures from as far back as 2001 and are not transferable
  - TIE credits are available only to incumbents and not new entrants

## Credit Adjustments

ACES
Alaska's Clear and Equitable Share

- Clarifies that deductions arising from Cook Inlet operations must first be used up in Cook Inlet and may not be shielded by tax ceilings
  - Consistent with existing regulations

# Alaska's Clear and Equitable Share (ACES) Proposal
## A Brief Review of the Governor's Proposed Changes to Oil Taxation

This review is a simplified explanation of the fiscal impact of major issues addressed by ACES. It is not intended to address every issue or to offer a complete technical discussion of the major issues.

The ACES bill addresses four major items:

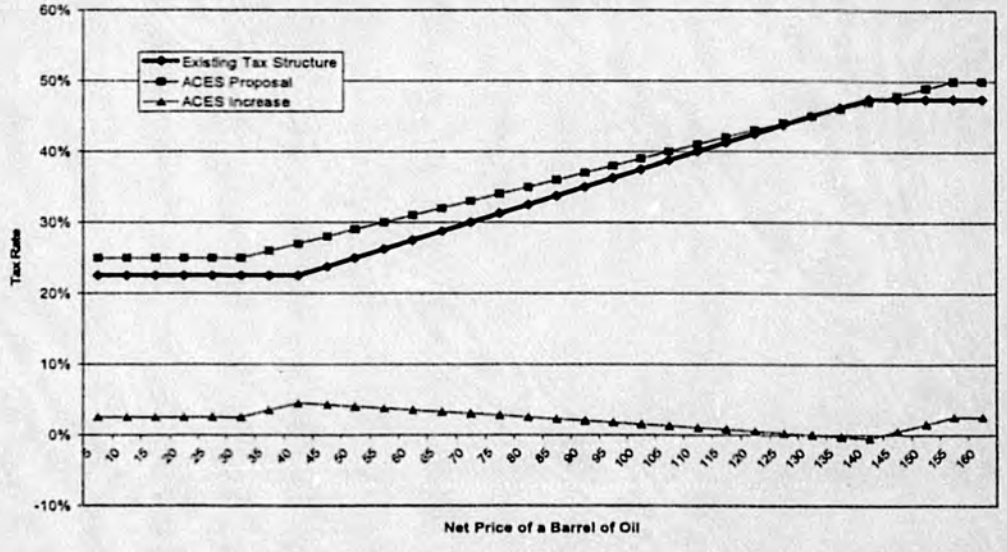
1. Base tax rate
2. A surcharge that increases revenue at higher oil prices
3. Tax credits, and
4. Information provided to the Department of Revenue.

**1. Base Tax Rate.** ACES raises the base tax rate from 22.5% to 25% of the profit on oil production. ACES also increases the minimum tax to 10% of the gross value of oil production (rather than profit) from the Prudhoe Bay and Kuparuk fields. PPT has a sliding scale that eliminates the minimum tax when oil prices are $15 per barrel or less. The ACES minimum tax rate offers better protection for the state (i.e., about 10% more revenue than PPT) if oil prices fall to very low levels.

**2. Surcharge.** Under PPT, a surcharge adds 0.25% to the base tax rate when the profit per barrel exceeds $40. ACES lowers the price level at which a surcharge is triggered, but also reduces the surcharge rate when oil prices exceed the trigger point. Under ACES, the surcharge adds 0.20% to the base tax rate when the profit per barrel exceeds $30.

The impact of changes to the base tax and surcharge are shown in Figure 1. ACES produces a higher tax rate at net prices below $130 per barrel or above $145 per barrel.

**Figure 1. Tax Rates Under Current Law and ACES**



As a rule of thumb, add $24 per barrel to the net prices shown in Figure 1 to obtain the selling price of ANS crude. ACES calculates the surcharge on the average annual price rather than monthly price as under PPT. Unless prices and production are highly volatile, the change in methodology should have relatively little impact.

The relevant portion of the chart for the near-term is between $30 and $80 per barrel, which is roughly equivalent to West Coast market prices of $54 to $104 per barrel. In that range, the total tax rate under ACES would average about 3.5 percentage points higher than under PPT. The maximum difference occurs when ANS crude sells for approximately $64 per barrel (profit of $40 per barrel), which is near the Department of Revenue's mid-term forecast. Because the surcharge rate under ACES is lower than under PPT, the difference in the total tax rate declines as the net price of oil increases.

The question begging discussion is whether ACES should be considered a tax increase. Figure 1 clearly shows that production taxes are generally higher under ACES than under PPT, but there is another factor to consider. That factor is that annual revenue under PPT is about $800 million less than anticipated.

ACES will generate more state revenue than the tax system the legislature implemented (PPT), but less state revenue than legislators *thought* they would get from the tax system they implemented. Those that argued that PPT provides an insufficient amount of oil revenue to the state will almost certainly point out that anticipated revenue under ACES is below levels anticipated under PPT. These people will argue that ACES is not a tax increase; it is a partial correction of a compromise that was based on inappropriate or inaccurate information.

On the other side of the argument, people will focus on the *share* of revenue rather than on the *amount* of revenue that goes to the state. State revenue under PPT is less than anticipated because the profit per barrel is much less than anticipated. Legislative Finance does not have the data required to determine whether or not actual shares of revenue are close to what was anticipated under PPT, but it is obvious that unanticipated production costs—which reduce profit and therefore reduce state revenue—do not accrue to the producers. From the perspective that ACES has generally higher tax rates than PPT (so increases the state share of revenue and reduces the share retained by producers at any given levels of price and costs of production) it is clear that ACES is a tax increase.

Converting *tax rates* to *revenue impacts* provides a less accurate (but more interesting) view. The following graphs are based on a simple model that holds production constant at 244 million barrels annually and deductible costs of production constant at $23.85 per barrel—numbers based on data published in the Spring 2007 Revenue Sources Book.

Figure 2 shows that changes to the base and surcharge tax rates under ACES can be expected to increase revenue by $450 million to $515 million annually in the $65 to $100 market price range. That amount is based on current levels of production and excludes

the impact of potential changes to tax credits. Revenue under ACES (relative to PPT) will fall if oil prices exceed $90, going negative at prices between $155 and $165.

**Figure 2. State Revenue Change Under the ACES Proposal**

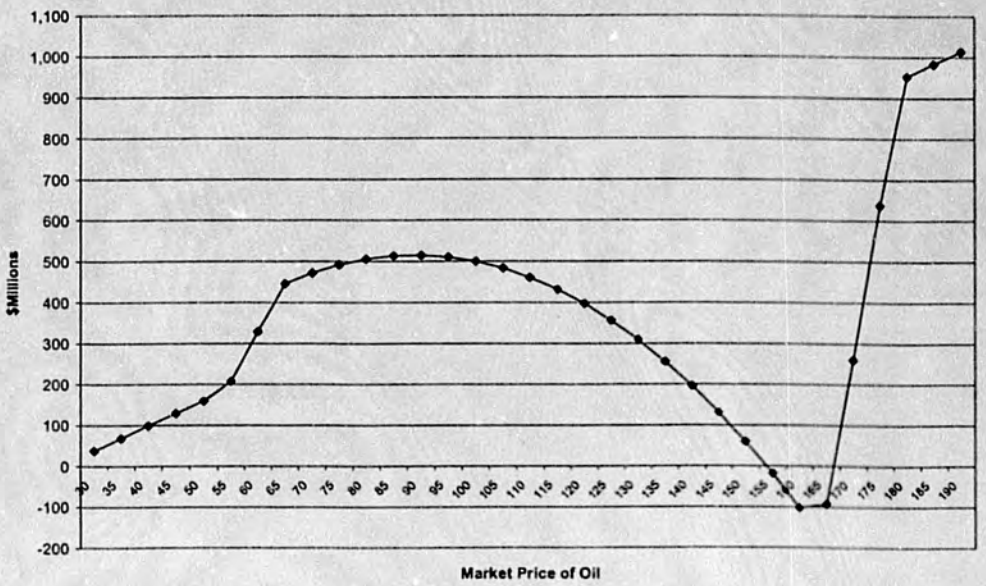
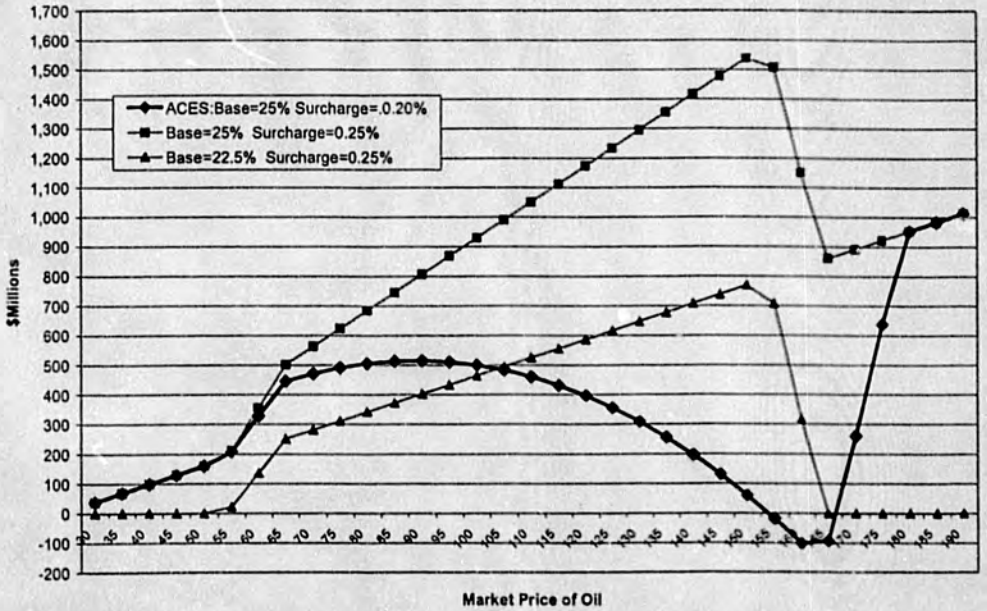



Figure 3 shows the sensitivity of revenue to changes in the base and surcharge tax rates. Adopting a 25% base rate and a $30 trigger point without reducing the surcharge rate

**Figure 3. State Revenue Change Under Variations of the ACES Proposal**



would generate significantly more revenue than PPT (or ACES) at all oil prices above $60. Retaining a 22.5% base rate and 0.25% surcharge rate while adopting a trigger point of $30 would generate less revenue than ACES at oil prices below $105, but more revenue at higher oil prices.

With variations in the base rate, surcharge rate and trigger point(s), the revenue curve can be designed to reflect whatever policy the legislature desires.

**3. Tax Credits.** Credits are arguably the most complex topic in the bill. A discussion of the fiscal impact of changes to tax credits would require knowing the amount (and type) of eligible credits that might be claimed. Legislative Finance does not have sufficient information to make projections. It should be clear, however, that reducing credits will increase revenue by more than indicated by a comparison of tax rates. In the figures above, the ACES line would be higher than shown if producers were allowed to claim fewer credits.

There are three types of tax credits. ACES makes a number of changes to tax credits as discussed below:

1. **Transitional Investment Credits.** These credits are for eligible capital expenditures incurred during the five years prior to the enactment of PPT. Statements in the press argue that because past investment events cannot be affected by changes to the production tax, these credits are essentially bonuses that reduce the tax liability of the major producers. ACES eliminates transitional credits.

   Legislative Finance has no projection of the value of transitional credits that would be claimed under PPT or the value of credits that ACES would eliminate, but a few conceptual statements may clarify the analysis. The credits:
   - are capped by time (they expire in 2013), by the amount invested in the transition period and by the amount invested in future years.
   - are not simply giveaways; they cannot be claimed without additional investment.
   - can be viewed as one-time bonuses that have no long-term impact on the tax structure.

   Lest these points be taken as supporting retention of the credits, it should be noted that the credits are likely to cost the state several hundred million dollars in lost revenue.

2. **Direct tax credits.** These credits are deducted directly from producers' tax liability. The state has little control over the amount of the direct credits applied; they require no appropriation and are deducted from revenue projections.

   Under ACES, tax credits remains at 20% of qualified capital expenditures, but no more than half the credit may be applied in any single year. This change may reduce volatility in the amount of credits applied in a given period and increase

the accuracy of revenue forecasts, but it has no significant long-term fiscal impact.

The allowable credit applied to a carried-forward annual loss is increased from 20% to 25% of the loss. This increase in available credits is offset by excluding losses based on lease expenditures in legacy fields. Legislative Finance has no projection of the fiscal impact of this change.

3. **Transferable tax credits**. These credits are generally applicable to small producers who make qualified expenditures but whose current tax liability is insufficient to apply the credits to their tax bill. Under PPT, small producers can claim a cash refund or sell/transfer the credits to a producer with tax liability sufficient to apply the credits. ACES eliminates the credits/refunds limit of $25 million per applicant per year.

   ACES establishes a new fund designed to ease the process of claiming/purchasing transferable tax credit certificates. Approximately $100 million to $200 million (dependent on the price of oil) would be appropriated annually to the fund. The Department of Revenue can use the fund to purchase eligible certificates, presumably without further appropriation. If the Department expects to expend the fund without further appropriation, a statement to that effect would reduce uncertainty regarding the need for an appropriation from the fund and the status of the fund with regard to the constitutionally mandated sweep of available general fund balances to the Constitution Budget Reserve Fund.

   An appropriation to purchase transferable credits was an item of contention in the FY08 budget process. The governor proposed an open-ended appropriation to pay for an estimated $25 million in claims. The legislature capped the appropriation at $25 million, but left the appropriation for FY07 open-ended. Based on the amount of credits purchased in FY07, a supplemental appropriation of $75 million may be required for FY08.

**4. Information requirements and other changes**. ACES includes several significant changes to the information that producers must provide to the state. The bill also includes several technical and conforming changes, and addresses unscheduled production interruption costs and auditing requirements of the Department. Explanation of these topics is best left to the Department of Revenue; the fiscal impact of such changes is minor relative to the impact of changes to tax rates and credits.

## ACES Proposal for Petroleum Taxation
## Tax Rate at Various Values of a Barrel of Oil

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Base Tax Rate: | 22.5% | | | | | | Base Tax Rate: | 25.0% | | | | | | |
| | | | | | | Surcharge: | 0.25% | | | | | | Surcharge: | 0.20% | | | | | | |
| | | | | | | Trigger Point: | $ 40.00 | | | | | | Trigger Point: | $ 30.00 | | | | | | |
| | | | | | | Maximum Surcharge: | 25.0% | | | | | | Maximum Surcharge: | 25.0% | | | | | | |
| | | | Existing Tax Structure (PPT) | | | | | | ACES Proposal | | | | | | ACES Increase | | | | | |
| Market Price | Taxable Value | Net Price | Surcharge Rate | Total Tax Rate | Base Revenue | Surcharge Revenue | Total Revenue | | Surcharge Rate | Total Tax Rate | Base Revenue | Surcharge Revenue | Total Revenue | | Base Revenue | Surcharge Revenue | Total Revenue | Percent of Revenue | Total Tax Rate |
| 30 | 1,500 | 6.15 | 0.00% | 22.50% | 337.5 | - | 337.5 | | 0.00% | 25.00% | 375.0 | - | 375.0 | | 37.5 | - | 37.5 | 11.1% | 2.50% |
| 35 | 2,720 | 11.15 | 0.00% | 22.50% | 612.0 | - | 612.0 | | 0.00% | 25.00% | 680.0 | - | 680.0 | | 68.0 | - | 68.0 | 11.1% | 2.50% |
| 40 | 3,940 | 16.15 | 0.00% | 22.50% | 886.5 | - | 886.5 | | 0.00% | 25.00% | 985.0 | - | 985.0 | | 98.5 | - | 98.5 | 11.1% | 2.50% |
| 45 | 5,160 | 21.15 | 0.00% | 22.50% | 1,161.0 | - | 1,161.0 | | 0.00% | 25.00% | 1,290.0 | - | 1,290.0 | | 129.0 | - | 129.0 | 11.1% | 2.50% |
| 50 | 6,380 | 26.15 | 0.00% | 22.50% | 1,435.5 | - | 1,435.5 | | 0.00% | 25.00% | 1,595.0 | - | 1,595.0 | | 159.5 | - | 159.5 | 11.1% | 2.50% |
| 55 | 7,600 | 31.15 | 0.00% | 22.50% | 1,710.0 | - | 1,710.0 | | 0.23% | 25.23% | 1,900.0 | 17.5 | 1,917.5 | | 190.0 | 17.5 | 207.5 | 12.1% | 2.73% |
| 60 | 8,820 | 36.15 | 0.00% | 22.50% | 1,984.5 | - | 1,984.5 | | 1.23% | 26.23% | 2,205.0 | 108.5 | 2,313.5 | | 220.5 | 108.5 | 329.0 | 16.6% | 3.73% |
| 65 | 10,040 | 41.15 | 0.29% | 22.79% | 2,259.0 | 28.8 | 2,287.8 | | 2.23% | 27.23% | 2,510.0 | 223.9 | 2,733.9 | | 251.0 | 195.0 | 446.0 | 19.5% | 4.44% |
| 70 | 11,260 | 46.15 | 1.54% | 24.04% | 2,533.5 | 173.1 | 2,706.6 | | 3.23% | 28.23% | 2,815.0 | 363.7 | 3,178.7 | | 281.5 | 190.6 | 472.1 | 17.4% | 4.19% |
| 75 | 12,480 | 51.15 | 2.79% | 25.29% | 2,808.0 | 347.8 | 3,155.8 | | 4.23% | 29.23% | 3,120.0 | 527.9 | 3,647.9 | | 312.0 | 180.0 | 492.0 | 15.6% | 3.94% |
| 80 | 13,700 | 56.15 | 4.04% | 26.54% | 3,082.5 | 553.1 | 3,635.6 | | 5.23% | 30.23% | 3,425.0 | 716.5 | 4,141.5 | | 342.5 | 163.4 | 505.9 | 13.9% | 3.69% |
| 85 | 14,920 | 61.15 | 5.29% | 27.79% | 3,357.0 | 788.9 | 4,145.9 | | 6.23% | 31.23% | 3,730.0 | 929.5 | 4,659.5 | | 373.0 | 140.6 | 513.6 | 12.4% | 3.44% |
| 90 | 16,140 | 66.15 | 6.54% | 29.04% | 3,631.5 | 1,055.1 | 4,686.6 | | 7.23% | 32.23% | 4,035.0 | 1,166.9 | 5,201.9 | | 403.5 | 111.8 | 515.3 | 11.0% | 3.19% |
| 95 | 17,360 | 71.15 | 7.79% | 30.29% | 3,906.0 | 1,351.9 | 5,257.9 | | 8.23% | 33.23% | 4,340.0 | 1,428.7 | 5,768.7 | | 434.0 | 76.8 | 510.8 | 9.7% | 2.94% |
| 100 | 18,580 | 76.15 | 9.04% | 31.54% | 4,180.5 | 1,679.1 | 5,859.6 | | 9.23% | 34.23% | 4,645.0 | 1,714.9 | 6,359.9 | | 464.5 | 35.8 | 500.3 | 8.5% | 2.69% |
| 105 | 19,800 | 81.15 | 10.29% | 32.79% | 4,455.0 | 2,036.9 | 6,491.9 | | 10.23% | 35.23% | 4,950.0 | 2,025.5 | 6,975.5 | | 495.0 | (11.4) | 483.6 | 7.4% | 2.44% |
| 110 | 21,020 | 86.15 | 11.54% | 34.04% | 4,729.5 | 2,425.1 | 7,154.6 | | 11.23% | 36.23% | 5,255.0 | 2,360.5 | 7,615.5 | | 525.5 | (64.6) | 460.9 | 6.4% | 2.19% |
| 115 | 22,240 | 91.15 | 12.79% | 35.29% | 5,004.0 | 2,843.9 | 7,847.9 | | 12.23% | 37.23% | 5,560.0 | 2,719.9 | 8,279.9 | | 556.0 | (124.0) | 432.0 | 5.5% | 1.94% |
| 120 | 23,460 | 96.15 | 14.04% | 36.54% | 5,278.5 | 3,293.1 | 8,571.6 | | 13.23% | 38.23% | 5,865.0 | 3,103.7 | 8,968.7 | | 586.5 | (189.4) | 397.1 | 4.6% | 1.69% |
| 125 | 24,680 | 101.15 | 15.29% | 37.79% | 5,553.0 | 3,772.9 | 9,325.9 | | 14.23% | 39.23% | 6,170.0 | 3,511.9 | 9,681.9 | | 617.0 | (261.0) | 356.0 | 3.8% | 1.44% |
| 130 | 25,900 | 106.15 | 16.54% | 39.04% | 5,827.5 | 4,283.1 | 10,110.6 | | 15.23% | 40.23% | 6,475.0 | 3,944.5 | 10,419.5 | | 647.5 | (338.6) | 308.9 | 3.1% | 1.19% |
| 135 | 27,120 | 111.15 | 17.79% | 40.29% | 6,102.0 | 4,823.9 | 10,925.9 | | 16.23% | 41.23% | 6,780.0 | 4,401.5 | 11,181.5 | | 678.0 | (422.4) | 255.6 | 2.3% | 0.94% |
| 140 | 28,340 | 116.15 | 19.04% | 41.54% | 6,376.5 | 5,395.1 | 11,771.6 | | 17.23% | 42.23% | 7,085.0 | 4,882.9 | 11,967.9 | | 708.5 | (512.2) | 196.3 | 1.7% | 0.69% |
| 145 | 29,560 | 121.15 | 20.29% | 42.79% | 6,651.0 | 5,996.9 | 12,647.9 | | 18.23% | 43.23% | 7,390.0 | 5,388.7 | 12,778.7 | | 739.0 | (608.2) | 130.8 | 1.0% | 0.44% |
| 150 | 30,780 | 126.15 | 21.54% | 44.04% | 6,925.5 | 6,629.2 | 13,554.7 | | 19.23% | 44.23% | 7,695.0 | 5,918.9 | 13,613.9 | | 769.5 | (710.2) | 59.3 | 0.4% | 0.19% |
| 155 | 32,000 | 131.15 | 22.79% | 45.29% | 7,200.0 | 7,291.9 | 14,491.9 | | 20.23% | 45.23% | 8,000.0 | 6,473.5 | 14,473.5 | | 800.0 | (818.4) | (18.4) | -0.1% | -0.06% |
| 160 | 33,220 | 136.15 | 24.04% | 46.54% | 7,474.5 | 7,985.2 | 15,459.7 | | 21.23% | 46.23% | 8,305.0 | 7,052.5 | 15,357.5 | | 830.5 | (932.6) | (102.1) | -0.7% | -0.31% |
| 165 | 34,440 | 141.15 | 25.00% | 47.50% | 7,749.0 | 8,610.0 | 16,359.0 | | 22.23% | 47.23% | 8,610.0 | 7,655.9 | 16,265.9 | | 861.0 | (954.1) | (93.1) | -0.6% | -0.27% |
| 170 | 35,660 | 146.15 | 25.00% | 47.50% | 8,023.5 | 8,915.0 | 16,938.5 | | 23.23% | 48.23% | 8,915.0 | 8,283.7 | 17,198.7 | | 891.5 | (631.3) | 260.2 | 1.5% | 0.73% |
| 175 | 36,880 | 151.15 | 25.00% | 47.50% | 8,298.0 | 9,220.0 | 17,518.0 | | 24.23% | 49.23% | 9,220.0 | 8,935.9 | 18,155.9 | | 922.0 | (284.1) | 637.9 | 3.6% | 1.73% |
| 180 | 38,100 | 156.15 | 25.00% | 47.50% | 8,572.5 | 9,525.0 | 18,097.5 | | 25.00% | 50.00% | 9,525.0 | 9,525.0 | 19,050.0 | | 952.5 | - | 952.5 | 5.3% | 2.50% |
| 185 | 39,320 | 161.15 | 25.00% | 47.50% | 8,847.0 | 9,830.0 | 18,677.0 | | 25.00% | 50.00% | 9,830.0 | 9,830.0 | 19,660.0 | | 983.0 | - | 983.0 | 5.3% | 2.50% |
| 190 | 40,540 | 166.15 | 25.00% | 47.50% | 9,121.5 | 10,135.0 | 19,256.5 | | 25.00% | 50.00% | 10,135.0 | 10,135.0 | 20,270.0 | | 1,013.5 | - | 1,013.5 | 5.3% | 2.50% |

Taxable value is estimated by subtracting variable costs ($7.22/bbl) and upstream costs ($4.058 billion) from the product of price and volume (244 mmbbls).
Net price subtracts $23.85/bbl (as determined by the computation for taxable value) from market price.

# State of Alaska

Department of Revenue

*Commissioner's Office*

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The Honorable Mike Doogan
House District 25 Representative
716 West 4th Avenue
Anchorage, Alaska 99501
(907) 269-0216

Dear Representative Doogan,

Thank you for your questions and we look forward to working with you through the ACES process. Your original questions and the Department's answers are set forth below. Please let me know if you require any additional material.

1. *Deputy Commissioner Marcia Davis said at the outset that the administration wanted to fashion a tax plan that encouraged industry investment and enhanced stat revenue. Are these goals listed in priority order; that is, in instances that inevitable trade-offs arose between the two goals, were they decided in favor of investment over revenue?*

The two goals are of equal value. The balance of the two goals leads to the ultimate objective to maximize the total value of oil and gas resources received by the state.

2. *Was the failure to predict income from the existing PPT all attributable to higher costs being claimed by the industry? If not, what other factors led to the spectacular chasm between what had been predicted for PPT and what was paid?*

The difference between the PPT forecast and actual tax revenues was due primarily to the inaccurate nature of the cost information used in the forecast calculation. The fiscal notes provided during the 2006 PPT debate relied on a variety of sources, including reports of outside experts, public statements from the North Slope producers, and some 2002 – 2004 cost information provided by the producers. The current PPT law does not require industry to supply detailed information relating to past or future costs, making it difficult for the department to determine whether the increases were due primarily to increase prices on current investments (price per item), or from an increased level of investment activity (more items purchased). This is one of the primary reasons ACES seeks to make the companies/taxpayers report their costs to us in real time--and prospectively.

To some extent we know that costs increased as a result of increased prices. The department has verified a global price escalation that took place over the past two years due to both the global increase in material and labor costs due to increasing demand, and the North Slope specific renewal of many industry sub-contracts. The contracts negotiated by producers in late 2005 and 2006 were at substantially higher prices than their earlier contracts. The prior lower priced contracts were negotiated at a time when producers believed that oil prices would fall, and that belief suppressed the pricing of contractors who knew that work would only materialized if the oil and gas projects could be shown to be profitable at approximately $20 barrel oil. We anticipate costs to rise slightly more before leveling off after the coming fiscal year, as additional North Slope contracts are re-negotiated.

3. *Since there has been no auditing of costs claimed by the industry under PPT, what confidence can we have that the administration's revenue projections based on that data are accurate?*

For our projections we have used the costs filed by the producers in their tax returns. Until these returns are audited, the appropriateness and accuracy of the reported cost amounts remain open questions. It is unlikely that the industry has understated its costs

ACES contains provisions that will rectify the situation the administration currently faces. ACES will improve DOR projections through stricter reporting requirements that are not contingent solely upon tax returns. It will include the obligation to supply DOR with documentation that is currently supplied by the unit operators to the other unit working interest owners relating to budgetary matters. This information will contain the operators' forecasted costs for the next 12 to 18 months associated with the Unit's approved operations plan. While these plans can be changed by the working interest owners over time, the DOR will likewise be made aware of those changes real time.

In addition, current information will be made more readily and timely available to the DOR by the ACES provisions that (1) enhance the DOR's ability to hire a sufficient number of qualified oil and gas tax auditors to speed up our auditing process, (2) create a comprehensive, workable database where the data is derived via computer from standardized monthly and annual tax reporting forms, and (3) an extended statute-of-limitations to complete any assessments on filed returns, which will enable DOR to focus on high priority audits without concern that lower priority audits will be timed out.

4. *Insofar as the administration's plan is based on confidential information, how will the legislature be able to satisfy itself that such data is accurate and is being interpreted properly?*

The economic models created by DOR and DNR personnel that analyze various tax proposals were built using a substantial amount of confidential tax payer information, and confidential resource data, without which the models cannot be manipulated. We have been advised by the Department of Law that the legislature may only review this underlying confidential information when the legislature is in executive session and accompanied by signed confidentiality agreements. While this limits what we may allow legislator's to inspect prior to the start of the session, we are happy to share our methodology, including assumptions, so that legislators can understand the analytical underpinnings of the models as a first step to verifying the validity of their results.

5. *In what ways is the administration's tax plan "intended to drive new production?" What sort of research was performed to estimate the effect of the state's production tax policy on the industry's decisions to explore or develop? What other factors are involved? Where do state taxes rank in the hierarchy of industry decision-making?*

Investment decisions are influenced by a number of considerations including resource potential, tax structure, regulatory environment, infrastructure, political stability and many others. Although the resource itself is generally the most significant driver, each company must gage each of these elements according to its own strengths and investment objectives.

From a state's perspective, it is important to understand the relative value of its resource, in addition to how its other features compare to those of competing areas. The state's ability to acquire the greatest possible value for its resources, however, depends largely on the state's ability to understand and respond to investment behavior. This means that regulatory and fiscal systems must be structured in a way that allow companies to meet investor expectations efficiently, but allow the state flexibility in capturing the greatest share of the resource's economic rent.

In structuring a tax system, the state has many tools at its disposal which affect companies in different ways at different periods in a project's economic life cycle. The most significant elements affecting an area's investment attractiveness allow a company to recoup its initial investment dollars as soon as possible. Value contributed by the state through capital credits reduce an investor's up-front costs and have a much greater positive effect on a project's net present value than does a reduction in tax rates. When an oil company invests, its future cash flow has uncertainties because of unexpected reservoir performance, and uncertainty relating to oil price. The sooner it recovers its initial capital investment, the more able the producer is able to weather the downside risks associated with production and oil price.

Both royalties and production taxes reduce the net cash flow that a company receives in the same way that operating and capital expenses do. These factors were taken into

consideration in the Administration's modeling efforts, along with cost and sales price sensitivities.

The analysis done by the Administration was based on sampled range of real projects, currently posed for development in Alaska. We were able to model the impact of various tax structures on exploration and development of these projects within the context Alaska's cost environment. The analysis showed several interesting things.

One thing we found was that a straight gross tax rate, at anything like the rate that would be necessary to raise the kind of money that the state should expect to receive from its resource, resulted in quite unfavorable investment metrics across the development plays examined. We also examined a number of gross tax variations incorporating different exploration and development incentives, but were unable to find one that balanced our objectives as well as some of the net-based approaches.

6. *What is the history of industry investment in exploration and development in Alaska, in terms of dollars spent? Has Alaska's percentage of worldwide annual spending for exploration changed during the past 10 years?*

Please see attached documents.

7. *What happened to the "challenges of writing regulations for PPT" mentioned in the department's analysis of Aug. 3?*

The second round of regulations has been largely focused on describing lease expenditures and addressing joint interest auditing. The department anticipates that although challenges will remain, the ACES proposal will be more administrable and drafting regulations for ACES will be a simpler task.

ACES take a clearer approach to defining allowable lease expenditures by enabling the department to make determinations regarding what costs are included. The current PPT language requires the department make explicit exclusions, and to accept unit accounting conclusions regarding which costs qualify.

ACES also removes from consideration as leasehold expenses certain disputable classes of costs such as proportionate abandonment costs, crude oil topping plant costs, and replacement and repair costs associated with unscheduled reduced or shut in production, oil spills or gas releases. These clarifications greatly simplify the technical regulations relating to leasehold expenses.

8. *Is the administration considering contracting for auditors needed for any net profits tax?*

Yes. The department plans to use a contractor in the short-term, along with department auditors, for a compliance review focused on leasehold expenditures that is anticipated to begin immediately. The use of contractors, however, is not a sustainable solution for the state and are only planned to be used over the next 2-4 years. They will help to augment and fully develop the department's own upstream auditing ability and auditor training programs. Requirements for auditors will changes substantially during the first two years as our auditors are provided with the appropriate information.

9. *The original PPT was written as a method of getting a gas pipeline. Since that approach has failed, what will the administration be proposing for provisions that allowed producers to write gas line costs off against their oil taxes?*

The administration believes that a fair tax on oil should not impact the state's prospects for a gasline. ACES, as proposed, will not address the gasline directly but leave in place language from the existing PPT which disallows a gasline project from accruing certain credits (see below). The administration also believes that the most appropriate time to address any changes in the production tax as it applies to gas would be prior to the first open season, but at a time will more economic information is known about gas commercialization opportunities and gas projects are better defined.

AS 43.20.043 (f) of the existing PPT language states:
A taxpayer is not entitled to a credit under this section for expenditures that are made or incurred for the qualified capital investment or for qualified services made for exploration and development of gas that occur in the area of Alaska lying north of 68 degrees North latitude or that are made or incurred to transport gas from reserves located in the area of Alaska lying north of 68 degrees North latitude.

10. *What are the proposed credits for oil exploration and development credited against?*

The credits will offset liability for production taxes. To the extent a company's credits are larger than its production tax liability, the company may transfer credits to another taxpayer. In the case of qualified applicants that produce an average of 50,000 barrels per day or less, the applicant may seek a refund of the credits from the state.

**Tax liability = [(Value - Costs) x tax rate] - credits.**

**Value** = volume of oil x wellhead value*
**Costs** = allowable capital expenditures + operating expenditures
**Rate** = 25% + .2% for every dollar that net income** per barrel exceeds $30

*Wellhead value = ANS price – transportation costs (TAPS tariff)
* *Net income = Value - Costs

11. *What does allowing two years for claiming capital credits do to the state's revenue projections? How will the added uncertainty introduced into those projections by this provision be accounted for?*

We expect that allowing companies to claim capital credits for two years will actually improve the stability of the state's revenue projections. The effect of the 2 year spreading of costs is that a single high cost year gets spread over two years, muting its negative effect on state revenues. In addition, the state has an opportunity to anticipate and plan on the higher costs that will be experienced in the next ensuing year. Where costs are increasing steady state the state revenues experience no ill effect from the averaging across two years.

12. *What is a participating area?*

A participating area is a subset of an oil and gas unit that is considered reasonably proven to be capable of producing oil and gas in quantities that would enable the operator to earn a profit. By regulation, an Operator must form a participating area prior to production. The unit boundaries are surface boundaries. The participating area can be visualized as an underground water balloon, but with oil and/or gas as its contents, and the participating area's boundaries are the latex rubber balloon that encapsulates the oil and/or gas reservoir. Traditionally, most participating areas encapsulate the volume of oil and/or gas that is considered to be in communication and sharing the same reservoir pressure and other fluid and reservoir properties. Operators develop oil and gas fields within units on a participating area basis and the owners of leases that overlay any part of the participating area agree upon special Operating Agreement provisions to govern the operator's conduct of development of that Participating Area. The Operator submits and DNR approves a methodology for allocation of production and costs for the unitized leased acreage committed to the participating area.

13. *How much of the government take in the administration's charts is state take? What is included in state take, and how much is each of these segments worth?*

In our attempt to capture the state a fair share of Slope-wide revenues we have focused on the concept of the "share of the incremental dollar" or "marginal tax rate" ("MTR"), rather than "take."

The term "Government Take" refers to the percentage of economic rent going to government. This is the cumulative gross revenues less costs (before tax). It is a life-cycle concept involving all development costs, including a companies cost of capital. We use this concept in analyzing investment on new fields, where all (or most) of the costs will be incurred going forward.

'Take' does not work on legacy fields where most costs were incurred many years ago and have already been recovered. In addition, it does not work for examining a single

year, for if a lot of costs are incurred one year, and you are looking at take the next year, the results can be deceptive.

The Marginal Tax Rate (MTR) is derived by looking at total per barrel government revenues at one price, and then increasing the costs by one dollar. The difference in per barrel government revenues is the marginal tax rate. The MTR is appropriate when costs have been recovered, and it can be looked at for individual years. It is what many economists use to compare government revenues internationally.

Total government revenues include royalties (state, federal, and private), state property tax, state production tax, state corporate income tax, and federal corporate income tax. The relative amounts of these vary depending on price.

Under ACES, with our 2008 cost assumptions, at a $60/bbl U.S. West Coast ANS price, the marginal tax rate is about 69%. In other words, as the price of oil moves up one dollar, government gets 69 cents of that dollar. About 50 cents of that goes to Alaska, or about $4.6 billion. This is broken out as follows:

| | |
|---|---|
| Royalties | $1.9 B |
| Production tax (ACES) | $2.0 B |
| Property tax | $0.1 B |
| State corporate income tax | $0.6 B |
| | $4.6 B |

14. *If the government take is a measure of the net value of a barrel of oil, what is that net value? What has been taken out to reach it?*

See question 13

15. *Under what scenario would the gross floor kick in? Specifically, what would have to happen to oil price and/or costs to bring the gross floor into play? Why is the gross floor lower than the ELF take from Prudhoe Bay?*

The floor would kick in when the combination of prices and costs yields net income such that the tax derived under ACES would be less than a tax derived at 10% of the gross revenue at the point of production. Given our assumptions for cost in FY 2008, we estimate the floor would kick in for the combined legacy fields at $40 West Coast oil price.

Under ELF, the gross tax rate would have been 15% X the field-specific ELF. The 10% gross floor would kick in for Prudhoe at an ELF of 0.67. Our forecast would be for this to trigger in 2017. Prior to that, the ELF for Prudhoe Bay would still be above the 10% floor.

16. *Why does the gross floor provision require a less aggressive upside tax?*

There is the potential for significant new investment in both the Prudhoe Bay and Kuparuk River Units. A significant volume of known viscous and heavy oil is located within these two units, and its development will be costly. In addition, investments which slow the pace of decline by 1 or 2 percentage points can mean significant volumes of production at lower costs and thus result in significant revenue to the state. In balancing the lower costs associated with expanding existing developments in legacy fields with the importance of more costly new reservoir developments in these legacy fields, the administration struck a balance that more aggressively protected the state in a low oil price-high cost environment, and in return the administration left producers with a greater upside in the event of higher oil prices and lower costs. It is unreasonable to expect that the producers would proceed with high cost developments within legacy fields, having no protection on the downside, if there were not greater rewards received for taking the risks associated with costs and oil prices. Further, where enhancements to existing production in legacy fields have relatively lower costs compared to similar production volumes coming from new developments, this lower cost benefit is captured in the net tax structure, by lower costs being netted against gross revenues.

17. *The administration's world average figures use the mean "to kick out extreme numbers." If the extreme numbers are real, why would we kick them out?*

The purpose of looking at international "government take" numbers is to provide some guidance as to the fairness of the tax scheme, where "fairness" is measured against international norms. (Note that the notion of "government take" actually says very little about comparative investment attractiveness – which is also importantly a function of the size of the resource prize, and costs of exploration, development, and production.) The calculation of an "average" is indeed highly sensitive to data that falls in the extreme ends of the spectrum ("outliers") that is, an extreme value can significantly move the "average". However, an extreme value tells one little about "norms". The "median" statistic is not affected by outliers; accordingly, as a guide to fairness norms, the "median" provides more robust information.

18. *If, as we are told, North Slope oil production is declining by 6 percent a year, then next year we will be producing about 75,000 barrels a day less. If the administration's less aggressive upside tax leaves $1 a barrel on the table, what return in terms of exploration and development would make foregoing that $27,375,000 worthwhile?*

A: The administration's upside tax is not less aggressive than the current PPT structure. It proposes an increase in the net tax rate on legacy fields of 25% instead of the current 22.5%. In addition, ACES changes progressivities by having it begin at $30/bbl instead of PPT's current $40/bbl net income. While the rate of increase is slightly less aggressive (0.2% under ACES vs. 0.25% under PPT), the significance of the ACES' earlier start-up

is that PPT progressivity would not provide greater revenue to the state that that provided by ACES until oil prices were over $120/bbl.

Sincerely,

Pat Galvin, *Commissioner*
Department of Revenue

**Title:** **Capital Development Costs for ANS - Some Examples**

Preparer: Dick Tremaine, DOR-Tax

Purpose: To assist in determining capital expenditures on an historic basis

Key Assumptions: Data are taken from tax returns, public reports, and personal conversations. The data is accurate only to the extent it was reported accurately.

History:

Disclaimer: The Department of Revenue is in the process of reviewing and updating the data on which this analysis is based. As a result, future analysis could have different results.

Some of the information contained in this workbook is privileged, confidential or otherwise protected from disclosure. If you are not the intended recipient, any use, dissemination, disclosure, distribution or copying is strictly prohibited.

# Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

## Millions of nominal Dollars [dollars of the day]

| | BP | | | ARCO/ConocoPhillips | | | Exxon | | | Other | | | All Companies | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Exp | Dev | Tot | Exp | Dev | Tot | Exp | Dev | Tot | Exp | Dev | Tot | Exp | Dev | Tot |
| 1975 | | | | | | | | | | | | | | | 3,827 |
| 1976 | | | | | | | | | | | | | | | 1,166 |
| 1977 | | | | | | | | | | | | | | | 890 |
| 1978 | | | | | | | | | | | | | 274 | 400 | 674 |
| 1979 | | | | | | | | | | | | | 174 | 1,282 | 1,456 |
| 1980 | | | | | | | | | | | | | 176 | 1,604 | 1,780 |
| 1981 | | | | | | | | | | | | | 419 | 3,104 | 3,523 |
| 1982 | | | | | | | | | | | | | 647 | 3,839 | 4,486 |
| 1983 | | | | | | | | | | | | | 818 | 1,100 | 1,918 |
| 1984 | | | | | | | | | | | | | 258 | 1,193 | 1,451 |
| 1985 | | | | | | | | | | | | | 514 | 1,547 | 2,061 |
| 1986 | | | | | | | | | | | | | 288 | 771 | 1,059 |
| 1987 | | | | | | | | | | | | | 288 | 1,020 | 1,308 |
| 1988 | | | | | | | | | | | | | 36 | 765 | 801 |
| 1989 | | | | | | | | | | | | | 132 | 748 | 880 |
| 1990 | | | | | | | | | | | | | 96 | 1,061 | 1,157 |
| 1991 | | 684 | 684 | | 343 | 343 | | 151 | 151 | | | | 120 | 1,178 | 1,298 |
| 1992 | | 573 | 573 | | 294 | 294 | | 124 | 124 | | | | 216 | 991 | 1,207 |
| 1993 | | 591 | 591 | | 416 | 416 | | 140 | 140 | | | | 192 | 1,148 | 1,220 |
| 1994 | | 564 | 564 | | 152 | 152 | | 93 | 93 | | | | 72 | 808 | 892 |
| 1995 | | 542 | 542 | | 124 | 124 | | 82 | 82 | | | | 84 | 748 | 856 |
| 1996 | | 551 | 551 | | 188 | 188 | | 87 | 87 | | | | 108 | 826 | 922 |
| 1997 | | 687 | 687 | | 274 | 274 | | 109 | 109 | | | | 96 | 1,070 | 1,142 |
| 1998 | | 700 | 700 | | 705 | 705 | | 155 | 155 | | | | 72 | 1,560 | 1,608 |
| 1999 | | 400 | 400 | | 664 | 664 | | 115 | 115 | | 50 | 50 | 48 | 1,179 | 1,239 |
| 2000 | | 670 | 670 | | 725 | 725 | | 150 | 150 | | 100 | 100 | 60 | 1,545 | 1,697 |
| 2001 | 34 | 714 | 748 | 108 | 612 | 720 | | 200 | 200 | 10 | 110 | 120 | 152 | 1,636 | 1,788 |
| 2002 | 9 | 439 | 448 | 102 | 434 | 536 | | 172 | 172 | 15 | 9 | 24 | 126 | 1,054 | 1,180 |
| 2003 | 0 | 416 | 416 | 75 | 386 | 461 | | 160 | 160 | 15 | 8 | 23 | 90 | 970 | 1,060 |
| 2004 | | 412 | 412 | 35 | 400 | 435 | | 160 | 160 | 32 | 8 | 40 | 67 | 980 | 1,047 |
| 2005 | | | | 64 | 650 | 714 | | | | | | | | | |
| 2006 | | | | 131 | 629 | 760 | | | | | | | 300 | 1,400 | 1,700 |

**Sources:**

1975-1989: Data from the "International Oil Tax Comparison Study", April 1990. Study did not provide a breakdown by company and no detail for the years 1975-1977.

1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska. Various published sources. A breakdown by company provided, but no breakout of exploration cost and development costs. Exploratory costs assumed to follow $12 million dollar per well rule of thumb.

2001-2004 Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports, publications/extrapolations for others. Breakout of capex by company & type Capex spending.

2006 Tax returns were submitted on March 31, 2007 for the period April 1, 2006 through December 31, 2006 - a nine-month period, also known as the "true-up" period. In order to present a data set that is consistent with other annual cost data, we assumed that spending during the nine-month period reported was representative of spending for calendar year 2006. Under this assumption, we calculated one-year's costs by multiplying the total costs reported by 1.33. **It is important to note that these IMPLIED costs represent expenditures in calendar year 2006, not fiscal year 2007.**

# State of Alaska

**Department of Revenue**
***Commissioner's Office***

**SARAH PALIN, GOVERNOR**
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0405
Phone: (907) 465-2300
Fax: (907) 465-2394

To: All Members of the Legislature

October 24, 2007

Dear Members:

I am distributing this attached document for your records entitled, *Capital Spending on North Slope Wells, Field Facilities and Exploration.* The document was compiled by the Department from publicly available data (individual company data) and tax data aggregated by the Department (All Companies data) relating to North Slope production costs.

A previous version, distributed as an attachment to a 10-17-07 letter from the Department of Revenue to Representative Doogan contained erroneous 2005 and 2006 data. Please replace any copies you may have with the attached document. We apologize for the confusion.

Sincerely,

Marcia Davis, *Deputy Commissioner*
Department of Revenue

Alaska Department of Revenue

Prepared March 15, 2005

# Capital Spending on Alaska's North Slope Wells, Field Facilities and Exploration

## Millions of nominal Dollars [dollars of the day]

| | BP | | | ARCO/ConocoPhillips | | | Exxon | | | Other | | | All Companies | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Exp | Dev | Tot | Exp | Dev | Tot | Exp | Dev | Tot | Exp | Dev | Tot | Exp | Dev | Tot |
| 1975 | | | | | | | | | | | | | | | 3,827 |
| 1976 | | | | | | | | | | | | | | | 1,166 |
| 1977 | | | | | | | | | | | | | | | 890 |
| 1978 | | | | | | | | | | | | | 274 | 400 | 674 |
| 1979 | | | | | | | | | | | | | 174 | 1,282 | 1,456 |
| 1980 | | | | | | | | | | | | | 176 | 1,604 | 1,780 |
| 1981 | | | | | | | | | | | | | 419 | 3,104 | 3,523 |
| 1982 | | | | | | | | | | | | | 647 | 3,839 | 4,486 |
| 1983 | | | | | | | | | | | | | 818 | 1,100 | 1,918 |
| 1984 | | | | | | | | | | | | | 258 | 1,193 | 1,451 |
| 1985 | | | | | | | | | | | | | 514 | 1,547 | 2,061 |
| 1986 | | | | | | | | | | | | | 288 | 771 | 1,059 |
| 1987 | | | | | | | | | | | | | 288 | 1,020 | 1,308 |
| 1988 | | | | | | | | | | | | | 36 | 765 | 801 |
| 1989 | | | | | | | | | | | | | 132 | 748 | 880 |
| 1990 | | | | | | | | | | | | | 96 | 1,061 | 1,157 |
| 1991 | | 684 | 684 | | 343 | 343 | | 151 | 151 | | | | 120 | 1,178 | 1,298 |
| 1992 | | 573 | 573 | | 294 | 294 | | 124 | 124 | | | | 216 | 991 | 1,207 |
| 1993 | | 591 | 591 | | 416 | 416 | | 140 | 140 | | | | 192 | 1,148 | 1,220 |
| 1994 | | 564 | 564 | | 152 | 152 | | 93 | 93 | | | | 72 | 808 | 892 |
| 1995 | | 542 | 542 | | 124 | 124 | | 82 | 82 | | | | 84 | 748 | 856 |
| 1996 | | 551 | 551 | | 188 | 188 | | 87 | 87 | | | | 108 | 826 | 922 |
| 1997 | | 687 | 687 | | 274 | 274 | | 109 | 109 | | | | 96 | 1,070 | 1,142 |
| 1998 | | 700 | 700 | | 705 | 705 | | 155 | 155 | | | | 72 | 1,560 | 1,608 |
| 1999 | | 400 | 400 | | 664 | 664 | | 115 | 115 | | 50 | 50 | 48 | 1,179 | 1,239 |
| 2000 | | 670 | 670 | | 725 | 725 | | 150 | 150 | | 100 | 100 | 60 | 1,545 | 1,697 |
| 2001 | 34 | 714 | 748 | 108 | 612 | 720 | | 200 | 200 | 10 | 110 | 120 | 152 | 1,636 | 1,788 |
| 2002 | 9 | 439 | 448 | 102 | 434 | 536 | | 172 | 172 | 15 | 9 | 24 | 126 | 1,054 | 1,180 |
| 2003 | 0 | 416 | 416 | 75 | 386 | 461 | | 160 | 160 | 15 | 8 | 23 | 90 | 970 | 1,060 |
| 2004 | | 412 | 412 | 35 | 400 | 435 | | 160 | 160 | 32 | 8 | 40 | 67 | 980 | 1,047 |
| 2005 | | | | | | | | | | | | | 30 | 1,268 | 1,301 |
| 2006 | | | | | | | | | | | | | 123 | 1,591 | 1,714 |
| 2007 | | | | | | | | | | | | | 194 | 1,787 | 1,981 |

**Sources:**

1975-1989: Data from the "International Oil Tax Comparison Study", April 1990. Study did not provide a breakdown by company and no detail for the years 1975-1977.

1990-2000: BP and Arco annual reports; Communications with BP, Arco Alaska. Various published sources. A breakdown by company provided, but no breakout of exploration cost and development costs. Exploratory costs assumed to follow $12 million dollar per well rule of thumb.

2001-2004 Communication with BP, ConocoPhillips 2002 & 2003 Annual Reports, publications/extrapolations for others. Breakout of capex by company & type Capex spending.

2005-2007: Unaudited taxpayer submitted EIC and PPT credit information as of 10/3/07. Exploration and development spending breakdown may contain inaccuracies, due to limited information and to the fact that costs that do not qualify for exploration credits may qualify under the PPT as development capital credits.

**Definitions:** **Exp = Exploration. Dev. = Development spending. Tot = Exploratons and development spending**

*Note: ARCO/Conoco Phillips exploration expenses in their Annual Reports include acquisition costs, lease rentals, and expensed overhead. BP's capex spend for 2001 and 2002 was only for capex.*

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 7:45 PM
**To:** Konrad Jackson
**Subject:** New Pom:Oil & Gas

Timothy Smith
Po Box 84083
512 Auburn Dr.
Fairbanks 99708-4083,
crusherak2@gci.net

907-479-8523

Alaska residents depend on you to do it right by your representing it's citizens and the governor. Vote for ACES and do the right thing for us.
Alaskans support our governor and her plan. Alaskans know it is the right thing to do, for all of us. Thank you.

## Konrad Jackson

**From:** Rep. Kurt Olson
**Sent:** Thursday, October 18, 2007 7:42 PM
**To:** Konrad Jackson
**Subject:** FW: ACES

-----Original Message-----
From: Stan Kaneshiro [mailto:skaneshiro@gci.net]
Sent: Tuesday, October 16, 2007 6:27 PM
To: Rep. Kurt Olson; Rep. Mike Chenault
Subject: ACES

I read in the Kenai paper that you two have problems with the Governor's plan. I know you are both pro oil industry, but I hope not so much that you turn your backs on the citizens of this State. We don't all work on the slope or on platforms and simply giving them what they want does not help oil workers in the long run.
The argument that higher taxes will stifle production is bogus. Easy oil supply is in decline and demand is increasing. Oil rich areas are increasingly hostile to the US and the oil companies have been cutting a fat hog off our oil for years.
Oil is nonrenewable. This is not a tax to incentive more acres be put in production or to enhance fish stocks. We need to get absolute top dollar for what oil we have left.
Please support passing a new PPT that gives us a better share for our oil.

Thanks,
Stan Kaneshiro
404 Jefferson St
Kenai

## Rep. Kurt Olson

**From:** Richard Hahn [rdhahn@eagle.ptialaska.net]
**Sent:** Thursday, October 18, 2007 10:28 AM
**To:** Rep. Carl Gatto
**Cc:** Rep. Kurt Olson
**Subject:** Fw:Letter to Governor Palin on ACES

----- Original Message -----
**From:** Richard Hahn
**To:** Sarah Palin
**Sent:** Tuesday, October 16, 2007 11:05 AM
**Subject:** ACES

Dear Governor Palin, Considering your apparent knowledge of the oil/ natural gas industry, it was surprising you would accede to Vic Kohring's propaganda (see his LTE, ADN, October 16, 2007) for your ACES proposal. The oil/gas producers will never stop investing in exploration for new sources of oil. Exploration is what they have done for decades to continue their profits. And, in the US, they don't have to worry about their leases being nationalized, a big incentive to stay here.

Another ADN article today said some oil is now selling at $86/bbl. That is about 10 times the selling price in 1998, and the oil producers were making a profit on each barrel of oil they shipped then. Are the Alaska oil producers shipping 10 times less oil in 2007? Of course not, they are making inordinate profits! And they want YOU to help them make an even higher profit margin. ACES will do that!

As long as Alaska allows the oil producers to subtract a myriad credits BEFORE their declared profits, the revenues received by Alaska will always be less than forecast. Alaska will also have to absorb more auditing costs and more litigation costs (and more aggravation and uncertainty), which must be subtracted from Alaska's net revenues.

There is a simple answer to this problem and more than 60% of your State's constituency subscribes to it. A simple tax on the market value of the resource puts an end to almost all questions about what the State is owed on a barrel of oil--or a cubic unit of natural gas--or a pound of minerals. Engineers are taught to use the "KISS Principle" in all designs. This Principle should be applied to the oil/gas producers' State taxes. If you and the Legislature use market value as a basis for oil and gas taxes, the truth then lies ONLY in how much of that resource was shipped. And that would be the only auditing Alaska would have to do.

I truly hope you and other elected officials are listening to the Alaska voters. The Alaska voter wants to be assured there will be no more $800 million shortfalls in forecast State oil revenues, due to differences of opinion, as to what is and what ain't oil producers' profits. Common sense dictates: 1) the oil tax be based on market value, and 2) telling the oil/gas producers to pay up or get out! I would like to have the millions of dollars they have spent the past few years in the media on propaganda, half-truths, and outright lies to achieve PPT. ACES, a variation of PPT, just is not close to the right answer!

I hope you and one of your senior staff read this far. Thanx much, if you did.

Sincerely,

Richard Hahn, a Republican voter
P.O. Box 2754
Soldotna, Alaska, 99669
907-262-8575
rdhahn@ptialaska.net

**Konrad Jackson**

**From:** Rep. Kurt Olson
**Sent:** Thursday, October 18, 2007 6:37 PM
**To:** Konrad Jackson
**Subject:** FW: Please do NOT change the PPT

---

**From:** Cindy Hallum [mailto:challum@carlile.biz]
**Sent:** Thursday, October 18, 2007 3:58 PM
**To:** Rep. Kurt Olson
**Subject:** Please do NOT change the PPT

Representative Olson,

I'm writing to ask you to please leave the Petroleum Production Tax alone until it's planned review in 2011 for several reasons.

First, the tax rate of 22.5% is augmented by the additional price index tax of $1 on every $4 over $40 per barrel. So at the current barrel price of $85, this makes the effective tax rate about 33%. This seems pretty reasonable to me. If we increase those taxes, the oil companies will look at other places where they can do business at a higher margin. We cannot afford to lose their business. The oil coming out of the ground now is declining and only new exploration is going to keep our State moving forward.

The current PPT tax is projected to bring in over a billion dollars in additional taxes this year. According to the website http://www.taxfoundation.org/research/show/287.html in the fiscal year 2005, Alaska spent $12,146 per person, ranking number 1 among all the States. Wyoming is number 2 with $7,861 and the average is $4,961. Why do we need more money for our State government? I believe that jobs are much more important to our future than a ton of money in the State coffers.

Also, please do not allow our governor to disallow the capital credit for the Ultra Low Sulfur Refinery that ConocoPhillips is planning on building. Without the credit, it probably won't get built, and that means running about 40 trucks non-stop hauling fuel from Fairbanks to Prudhoe. This is not the most efficient or environmentally conscious way to supply fuel for use in drilling, exploration, and operations on the North Slope.

I work at Carlile Transportation Systems, Inc. and our company depends heavily on the oil and gas industry. We are already suffering from the slowdown on the North Slope and the hold that the federal judge has on Shell's drilling plans. Our company, and indeed the whole Alaska economy, needs the business of our oil and gas partners to thrive.

Any activities that you can do to support these agendas is appreciated.

I look forward to seeing how you vote on this matter. Please consider these points when making your decision.

Thanks,
Cindy Hallum
Carlile Transportation Systems, Inc.
907-276-7797 x306

## Rep. Kurt Olson

**From:** Lester & Amy [lester@gci.net]
**Sent:** Wednesday, October 17, 2007 5:57 PM
**To:** Rep. Kurt Olson
**Subject:** special session

Mr Olson

In the matter of the special session, I would enchourage you to employ Occams razor " All things being equal the simplest solution is usually the best". Please work towards a gross tax. It is the best solution for Alaskans and makes the most sense.

Thank you , Amy Hubbard

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 4:54 PM
**To:** Konrad Jackson
**Subject:** New Pom:Oil & Gas

Jerry Mccutcheon
Po Box 101838

Anchorage 99510-1838,
susitnahydronow@yahoo.com

Johnston got confused it is not an EOR question on heavy oil about producing resevoir, they are separate resevoirs and should be taxed separately even though they are in the same leases.

**Konrad Jackson**

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 3:39 PM
**To:** Konrad Jackson
**Subject:** New Pom:Resources

William Harvey Jr
13720 Davis St

Anchorage 99516-3614,blueraven
bluedog@ak.net

Governor's proposed oil severance tax:

Please please vote for an increase in the oil severance fee. This is for a long time and it will help our grandchildren and their offspring for generations to come.

thanks

Wm Harvey

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 1:18 PM
**To:** Konrad Jackson
**Subject:** New Pom:Legislators

Lyndon Sikes
Po Box 101202

Anchorage 99510-1202,

Please read Compass article in the Anchorage Daily News, Saturday October 13, page B-5 by Larry Carr.
Then search your heart.

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 10:08 AM
**To:** Konrad Jackson
**Subject:** New Pom:Taxation

Sherry Whitstine
Po Box 871985

Wasilla 99687-1985,tswhit

You will never be able to redeem yourselves for agia, thinking you had to do something. That alone has devestated our state's future. So take my advise this time around and DO NOTHING!

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 9:29 AM
**To:** Konrad Jackson
**Subject:** New Pom:Oil & Gas

Lapriel Stephan
Po Box 112114

Anchorage 99511-2114,

276-5733

Definitely no new oil taxes.

**Konrad Jackson**

**From:** Shay Wilson
**Sent:** Thursday, October 18, 2007 8:13 AM
**To:** Konrad Jackson
**Subject:** New Pom:Taxation

Chriss Homan
2840 Devin Cir

Anchorage 99516-2070,
homan@gci.net

Please bring sanity back to our state. PPT has already brought in an extra $1 billion. All of it has been spent. Leave as is for a few years or LOWER the rate. We need to promote private investment. Industry is good for Alaska. Big government is BAD!

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Tuesday, October 16, 2007 4:55 PM
**To:** Konrad Jackson
**Subject:** New Pom:Governor

Sherry Whitstine
Po Box 871985

Wasilla 99687-1985,tswhit

Nationally Sarah said.....
Some are keeping us from developing our gas resources? THAT IS YOU Sarah !!!! Oh yeah, and all your demo- lib friends. You are nothing more then a self righteous snob, self promoting and self advising, and you girlfriend are on the wrong side of every issues that is important to this state's future.

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Sunday, October 14, 2007 1:32 PM
**To:** Konrad Jackson
**Subject:** New Pom:Oil & Gas

Justin Powell
1075 Trianon Dr

Fairbanks 99712-2743,
jpowell@acsalaska.net
460-7888
479-1214

I support ACES and want to see Alaska get a fair value for our resources for once. I hope that you can put Alaska's best interests first and not be swayed by the sob stories of big oil as they engage in the most profitable business in the world. We deserve an equitable share for our limited natural resources.

## Konrad Jackson

**From:** Shay Wilson
**Sent:** Sunday, October 14, 2007 1:07 PM
**To:** Konrad Jackson
**Subject:** New Pom:Oil & Gas

Richard Melms
4201 Leyden Rd

Anchorage 99516,richmelms
rdzmelms@alaska.net
907 3456184
907 3456184

Vote for Alaska's best interests not the oil industry! They are making record profits and the State should benefit from that. The previous legistlation was tainted by the actions of the oil industries "lap-dog"
legislators who sold the state out. We will be watching your performance!

**Konrad Jackson**

**From:** POMS@legis.state.ak.us
**Sent:** Thursday, October 04, 2007 12:04 PM
**To:** Konrad Jackson
**Subject:** New Pom:Oil & Gas

Stephen Early
8306 Huckleberry St

Anchorage 99502,
searly@gci.net
907-258-9972
907-440-7951

I wish that our represenitives would quit calling the price of our oil a tax. our represenitives must get across the fact that we are selling the oil to the oil companys.I lobbied all of our legislators for a set price of our oil 25% sounds good.no PPT

## Konrad Jackson

**From:** POMS@legis.state.ak.us
**Sent:** Thursday, September 27, 2007 9:19 PM
**To:** Konrad Jackson
**Subject:** New Pom:Taxation

Sherry Whitstine
Po Box 871985

Wasilla 99687-1985,tswhit

Without a stable tax regime, without the promise of a gas line, without exploration for gas and oil, without more oil production,the economic engines stops No matter what this is a lousy time to rush through a jury-rigged new tax program to support increased spending. This is a lousy time to be stampeded by Sarah.

**Konrad Jackson**

**From:** Rep. Jay Ramras
**Sent:** Monday, October 08, 2007 8:53 AM
**To:** Konrad Jackson
**Subject:** FW: Oil tax

-----Original Message-----
From: Frederick Dean [mailto:deansfs@alaska.net]
Sent: Monday, October 08, 2007 8:00 AM
To: Sen. Gary Wilken; Sen. Gene Therriault; Rep. David Guttenberg; Rep. Scott Kawasaki; Rep. Jay Ramras
Subject: Oil tax

Dear Legislators,

The Governor's proposal for revising the oil tax may contain some relatively small and reasonable improvements. However, I for one (among many?) fail to see why we expose ourselves to the vulnerability and problems that are clearly foreseeable as soon as you base things on "profits." I strongly urge that a fair rate be set but that it be based on production at the well head; then the only thing the State needs to audit is the accuracy of meters. Presumably mechanical devices will be less prone to discover ways to claim interpretive variations than those who make a profession of such work.

This is redundant with my earlier pleas, but the issue seems pretty clear!

Sincerely,
Fred Dean

Frederick C. Dean
810 Ballaine Road, Fairbanks, AK 99709 U.S.A.

Tel. (907) 479-6607 e-mail <deansfs@alaska.net>

# What is ACES?

ACES
Alaska's Clear and Equitable Share

## Tools to Protect the State's Interests

- Competitive Pay for Auditors **Sec. 10. AS 39.25.110**
- Information Needed by the State
  - Cost forecasts **Sec. 49. AS 43.55.040**
  - Expenditure details in a timely manner and useful format
    - **Sec. 46. AS 43.55.030(a)[annual report-producer],**
    - **Sec. 48. AS.43.55.030 [annual report-non-producer], ,**
    - **Sec. 49. AS 43.55.040(5),(6)[explicit power to require info]**
    - **Sec. 51 AS 43.55.110 [electronic filing and payment]**
  - Information sharing between state agencies
    - **Sec. 2. AS 38.05.035(a), Sec. 13. AS 43.05.230(h)**
  - Public disclosure of certain information **Sec 61. AS 43.55.890**

# What is ACES?

ACES
Alaska's Clear and Equitable Share

## Tools continued…

- Clear Rules
  - Define allowable lease expenditures
    - **Sec. 56. AS 43.55.165(a)**
  - Exclude inappropriate deductions (Corrosion / DR&R/ COTP)
    - **Sec. 58. AS 43.55.165(e)**
  - Clarification of Annual Loss Carry-forward of unused Lease expenditures
    - **Sec. 54. AS 43.55.160(e);**
    - **Sec 55 AS 43.55.160(f)**
- Statute of Limitations
  - Extended for completing assessments from 3 to 6 years.
    - **Sec.50. AS 43.55.075**

# What is ACES?

ACES
Alaska's Clear and Equitable Share

## Hybrid Tax System

- Net Tax Base
  - 25% Rate **Sec. 17. AS 43.55.011(g)**
  - Adjustments to Progressivity
    - **Sec. 17. AS 43.55.011(g)[Trigger price];**
    - **Sec. 18. AS43.55.011(h)[rate]**
  - Adjustments to Qualified Capital Credits
    - **Sec. 21. AS 43.55.011(m)[Cook Inlet];**
    - **Sec. 26. AS 43.55.023(a)[2 year spread, geo info to DNR, legacy restriction];**
    - **Sec.27. AS 43.55.023(b) [no legacy carry forward];**
    - **Sec 31. AS 43.55.023(l) [no transferable cert. for tax exempt ];**
  - Improved credit system for explorers
    - **Sec. 37- 43 AS 43.55.025(b)-(l) [Exploration Credit changes]**
    - **Sec. 44 AS 43.55.025(l) [credit for old Seismic data]**
    - **Sec. 45. AS 43.55.028 [Fund to purchase capital and explorer credits]**
  - Elimination of TIE credits (for past expenditures)
    - **Sec. 63. AS 43.55.023 (f)**

# What is ACES?

ACES
Alaska's Clear and Equitable Share

## Hybrid Tax System continued…

- Gross Tax Floor (Not Additive) **Sec.16. AS.43.55.011(f)**
  - 10% on Prudhoe Bay and Kuparuk Fields
  - Will kick in at low oil prices

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Web posted Sunday, September 16, 2007

# Meet Kevin Banks, Alaska's Oil and Gas Division director

**By Tim Bradner**
*Alaska Journal of Commerce*



Alaska Division of Oil and Gas director Kevin Banks has had a busy year as activity in the state's oil fields exploded. The division has struggled to find and keep employees, but is starting to make progress on that front, Banks said. *PHOTO/Tim Bradner/For the Journal*

It has been a hectic year at the state Division of Oil and Gas, the state agency that looks out for Alaska's ownership interests in oil and gas production from state-owned lands. So if things were to slow down a little in Alaska's oil patch after last winter's overheated levels of activity, it wouldn't bother Kevin Banks, who heads the agency.

Construction and other industry activity soared last winter on the Slope. This left explorers and incumbents alike scrambling to find suppliers and equipment, and paying higher-than-expected prices for oilfield services in the hot North Slope oil patch economy.

The year started off with a bang for the oil and gas division, too. When Gov. Sarah Palin took office last December, the two top positions in the division - the director and deputy director - were vacated by resignations. Banks and Kurt Gibson were moved up from the commercial section to take over as acting director and deputy.

Then the governor dropped in her Alaska Gasline Inducement Act, a key initiative that brought Banks, Gibson and other division staff to Juneau to help Palin develop legislation and work with state legislators on her gas pipeline plan.

And then Palin and her resources chief, Commissioner Tom Irwin, handed the division a new responsibility: Insuring the mechanical integrity of petroleum production facilities. This required the establishment and staffing of a new Petroleum Systems Integrity Office within the division.

Amid all this, the division has been scrambling for qualified people to fill positions during a tough economic time for recruiting petroleum professionals - they're all working elsewhere. The governor and Legislature have been generous with financial resources for the division, but hiring has been a major preoccupation.

"Kurt and I technically occupy four positions, acting director and deputy director, as well as petroleum market analyst and petroleum investments manager," Banks said.

He hopes to recruit added commercial staff to fill the latter two positions. The division is also still trying to hire a petroleum engineer to fill the position vacated by the retirement of agency veteran Bill Van Dyke. It has been unable to do so, however. Banks is concerned about others retiring.

"Depending on how you count the numbers, the division could lose 42 percent of its oil and gas staff within the next five years," he said.

On staffing, the division has just brought on two new people: Cody Rice is a new

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(W.Coast delivery)
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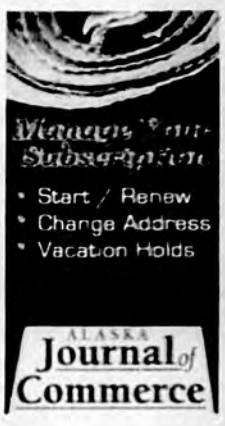
Alaska Star.com

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SOMETHING TO SING ABOUT ...







Petroleum Economist, filling a position that has been vacant almost a year in the division's commercial section. Another new hire in the commercial section is Alan Dennis, who was formerly with ConocoPhillips in Houston. Dennis should be working in the office by October, Banks said.

Filling the petroleum engineer position is a worry.

"We've advertised for a petroleum engineer locally, through the Society of Petroleum Engineering newsletters and Houston, Texas, newspapers and we continue to shake the trees for qualified candidates," Banks said. "Industry-wide demand for people with these skills is very high and state salary levels are a factor."

"Our audit section is also thin. Normal attrition and people moving on to new jobs has taken a real toll and has left us chronically short. We're considering options to change this situation," Banks said.

Similar problems in the division's leasing and permitting section have, for now, been resolved with a few new hires, however.

As for the upcoming winter work season on the Slope, Banks believes things will be a little slower than last winter, based on the pace of permit applications so far this summer. Companies planning work usually apply to regulatory agencies for their permits in late summer.

More requests could still come in, but if things slow a bit it will still be a good, full season of employment for service contractors and support companies, Banks said.

Last year's overheated season may actually have done some damage to the state's attractiveness for exploration because companies that drilled exploration wells experienced some big cost increases. That was because there was intense competition for skilled oilfield labor and equipment, almost everything from drill rigs to rolligons.

Banks is particularly concerned about how Alaska is being viewed in the corporate offices of FEX and its owner, Talisman Energy, as well as Eni. Both companies were active in drilling exploration wells last winter, and Banks hopes that the experience with cost increases won't dampen plans for new work in Alaska.

FEX needs to test potential discoveries it made in the National Petroleum Reserve-Alaska, but the Division of Oil and Gas does not yet know if the company intends to do a full-blown or a more limited program to assess what it found.

Banks does know that Eni is very concerned with cost increases and he is uncertain whether the company will proceed with development of its Nikaitchuq offshore prospect this year. Last year the state rejected Eni's request for royalty modification at Nikia, but that was because the project appeared economically viable under the current state Petroleum Profits Tax. ENI has indicated that its costs are now higher than previously estimated.

Another concern Banks has is the uncertainty over new lease sales in the NPR-A, given the controversy, litigation and delays surrounding every sale proposed by the BLM, the most recent being the federal agency's proposed sale of very prospective leases near the Teshekpuk Lake area of the northeast NPR-A.

"This has got to be a major concern for companies now holding leases in the NPR-A because they need to be able to bid on tracts adjacent to their leases to fill out their land position," for efficient exploration programs, Banks said. BLM is also trying to work out issues related to unitization, which will enable companies to group leases that are expiring in units for further development.

The state is mindful of the pace of exploration and development in NPR-A because Alaska will receive 50 percent of production royalties from the federal reserve.

Yet another concern for Banks is uncertainty over Pioneer Natural Resources Co.'s Facility Access Agreement with Kuparuk River Unit owners that will enable Pioneer to process fluids from its new Oooguruk project in facilities owned and operated by the Kuparuk Unit.

"Oooguruk is still on track for startup in 2008 but we have no direct information about the access agreement," Banks said.

Facility use agreements between established companies on the Slope are common but involve firms that are partners in producing fields and infrastructure. Pioneer's

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agreement is the first involving a company that is outside the existing producers.

If things break down, the state may have to play a role in getting an access deal, Banks said. But it is preferable that the agreement be worked out between the companies on a purely commercial basis.

Another issue on the division's plate is the ongoing dispute over lease ownership at Point Thomson, a large natural gas and condensate discovery 60 miles east of Prudhoe Bay. The state has cancelled leases at Point Thomson and is locked in protracted litigation with ExxonMobil Corp., BP and Chevron, the companies owning the leases in question.

Banks said that if the state prevails and does get clear title to the leases, his division may explore alternatives to leasing other than the state's conventional areawide lease sales, where unleased acreage is periodically offered. A different approach to leasing might an involve production sharing agreement or other mechanism used elsewhere instead of a conventional oil and gas royalty, he said.

There are many alternatives now in the state's leasing tool-kit including work commitments and net profits share royalties but an entirely new approach may require legislation, Banks said.

Tim Bradner can be reached at tim.bradner@alaskajournal.com

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# Oil and Gas Reporting and Disclosure In Selected Countries

***Focus On Cost / Field Detail Reporting***

# Summary

- **In the vast majority of regimes around the world companies are required to disclose detailed data**
  - Prospective (plans) and actual
  - Typically down to well / field level detail
- **Data is provided to both resource-management and fiscal/taxation authorities**
  - Intra-governmental sharing
  - Greater flow to, rather than from, fiscal authorities
- **Reporting and public disclosure are two separate issues**
  - Public reporting is common
  - Though typically in aggregated or summary form

# Why Does Alaska Need To Receive Data ?

- **Required in order to properly manage the State's resources**
  - "The energy resources of this State belong to the people of Alaska[1]"
- **Full understanding of technical and commercial factors**
- **Ability to plan and control**
  - Exploitation policy
  - Budget
- **These are universal principles**
  - Not unique to Alaska

[1] Adapted from Accountability principle of Alberta Royalty Review Panel

# Forms Of Reporting and Sharing

- **Production and well data**
  - Monthly or as completed
- **Annual or Semi-Annual field-level information**
  - Typically collected by Ministry / Regulatory Body
- **Tax returns**
  - Collected by fiscal authority
- **Intra-Governmental Sharing**
  - Degree of sharing varies by country
  - Typically greater sharing by Ministry / Regulatory Body than by fiscal authority

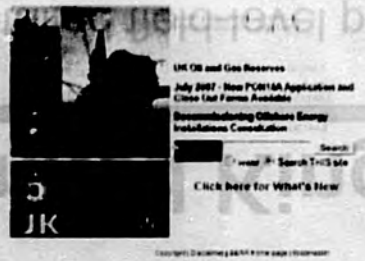
# Public Reporting

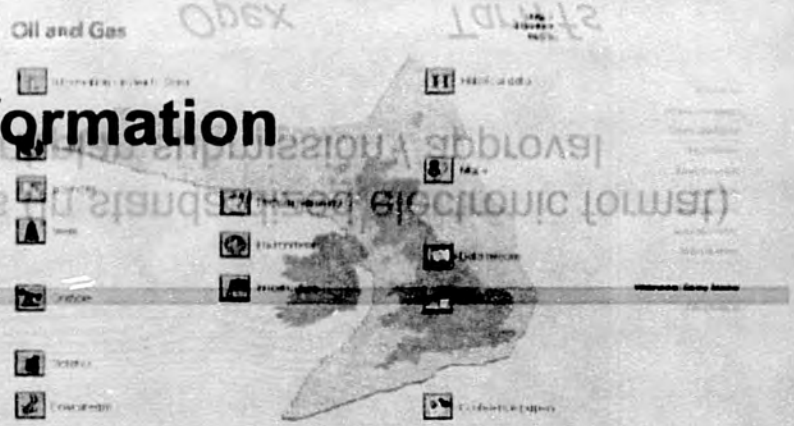
- **Mostly in aggregated / summary form**
- **Some countries provide field-level summaries**
  - Reserves
  - Capex
    - More often as total, but sometimes as annual time series
- **Opex rarely disclosed at field-level, although subscription services do provide this**
  - Data quality dependent upon various sources, including "oil company guidance"
  - Sometimes occurs in stock market documentation released by (usually) smaller companies

# Examples Of Data Disclosure (Production and Cost Focus)

# UK Summary

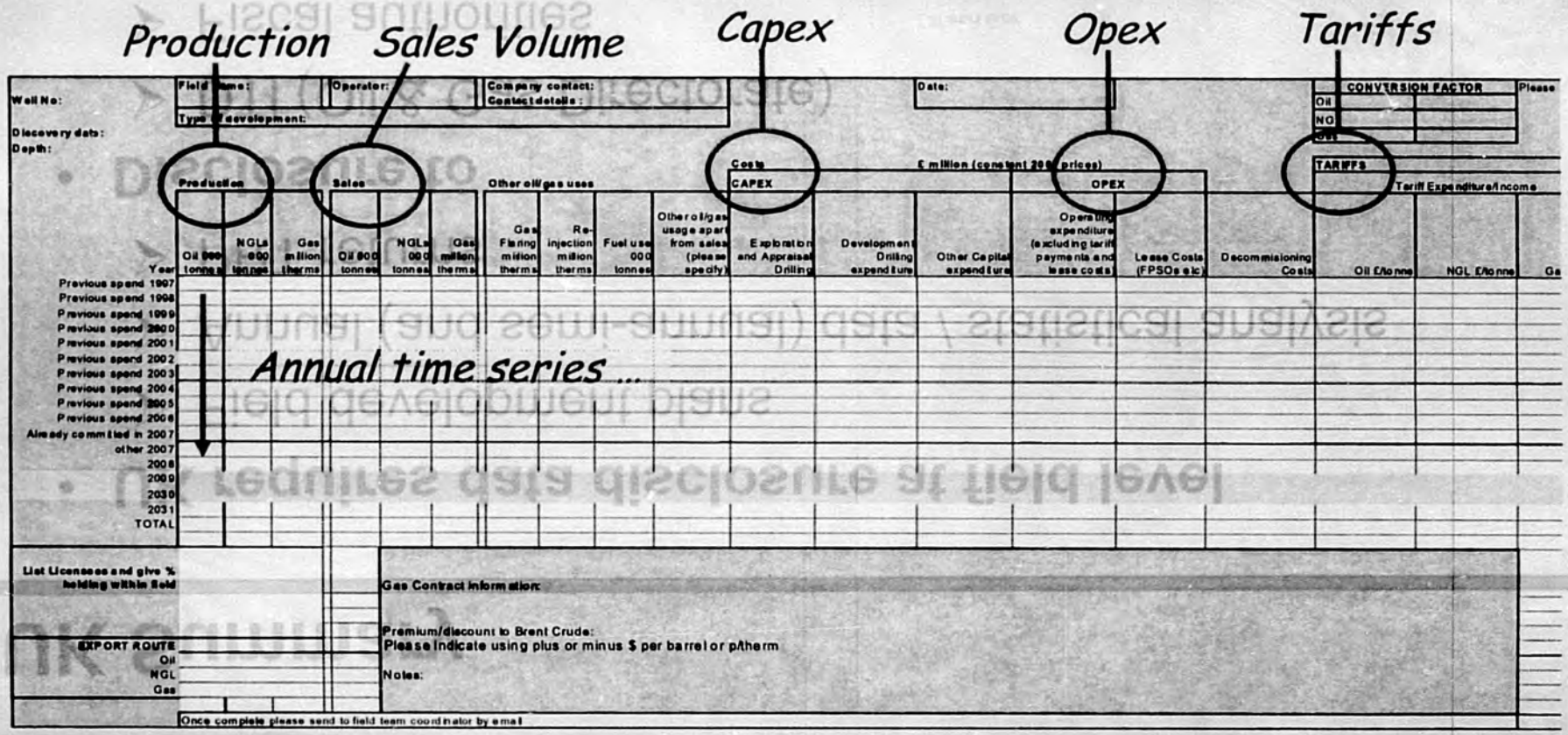
- **UK requires data disclosure at field level**
  - Field development plans
  - Annual (and semi-annual) data / statistical analysis
  - PRT returns
- **Disclosure to**
  - DTI (Oil & Gas Directorate)
  - Fiscal authorities
- **Publication of aggregated information**



# United Kingdom

Detailed field-level production and cost projections (in standardized electronic format) are required as part of the Field Development plan submission / approval



# United Kingdom

## Annual UKCS Income and Expenditure summarized on an annual basis

**Income from and Expenditure on UK Continental Shelf Exploration, Development and Operating Activities**
**(£ million)**

*Sales* — Income — Expenses — *Opex* — Capital Expenditure — *Capex* — Prices

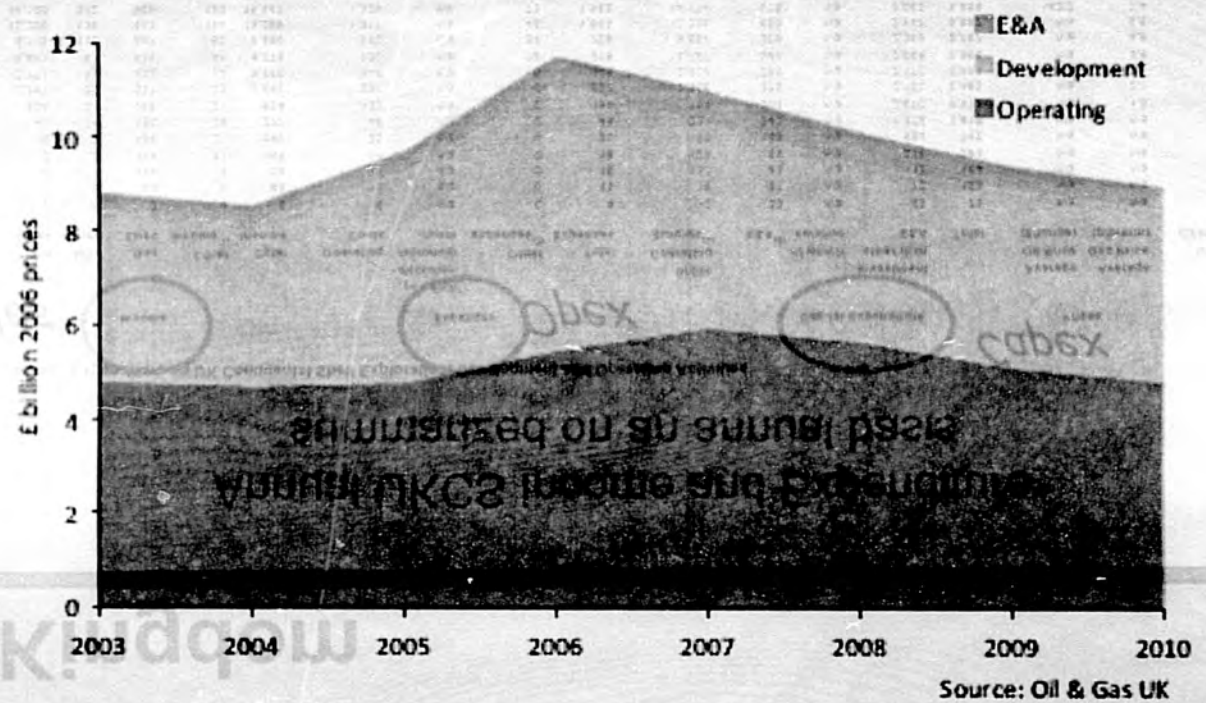
| | Oil Sales | NGL Sales | Gas Sales | Other Income[1] | Total Income | Operating Costs | of which decommissioning costs | Other expenses[2] | Total Expenses | Gross Operating Surplus[3] | E&A[4] | of which seismic | Investment other than E&A | Total | Average Oil Price ($/tonne) | Average Gas Price (p/therm) | GDP Deflator (2003=100) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1970 | 0 | 0 | 0 | 4 | 5 | 6 | n/a | 0 | 6 | -2 | 20 | n/a | 53 | 73 | n/a | n/a | 9.9 |
| 1971 | 0 | 0 | 60 | 5 | 65 | 11 | n/a | 0 | 11 | 74 | 57 | n/a | 72 | 129 | n/a | n/a | 10.6 |
| 1972 | 0 | 1 | 114 | 9 | 124 | 15 | n/a | 0 | 15 | 110 | 43 | n/a | 112 | 164 | n/a | n/a | 11.7 |
| 1973 | 0 | 2 | 153 | 11 | 146 | 18 | n/a | 0 | 18 | 129 | 69 | n/a | 215 | 284 | n/a | n/a | 12.6 |
| 1974 | 0 | 3 | 166 | 21 | 190 | 20 | n/a | 0 | 20 | 170 | 163 | n/a | 584 | 787 | n/a | n/a | 14.4 |
| 1975 | 43 | 16 | 193 | 29 | 277 | 46 | n/a | 0 | 46 | 231 | 242 | n/a | 1,374 | 1,616 | n/a | n/a | 18.3 |
| 1976 | 624 | 21 | 289 | 21 | 924 | 130 | n/a | 0 | 130 | 794 | 301 | n/a | 2,570 | 2,872 | n/a | 1.9 | 21.1 |
| 1977 | 2,157 | 29 | 317 | 23 | 2,662 | 207 | n/a | 0 | 207 | 2,356 | 375 | n/a | 2,107 | 2,482 | n/a | 2.1 | 24.0 |
| 1978 | 2,771 | 35 | 432 | 12 | 3,240 | 346 | n/a | 0 | 346 | 2,904 | 281 | n/a | 2,170 | 2,451 | n/a | 3.1 | 26.8 |
| 1979 | 5,841 | 53 | 538 | 44 | 6,276 | 502 | n/a | 16 | 519 | 5,757 | 241 | n/a | 2,064 | 2,305 | n/a | 3.8 | 30.7 |
| 1980 | 8,715 | 122 | 647 | 92 | 9,580 | 692 | n/a | 34 | 726 | 8,854 | 379 | n/a | 2,388 | 2,767 | n/a | 4.9 | 36.7 |
| 1981 | 12,206 | 135 | 843 | 114 | 13,298 | 1,017 | n/a | 45 | 1,065 | 12,235 | 550 | n/a | 2,847 | 3,397 | n/a | 6.5 | 40.8 |
| 1982 | 14,139 | 312 | 956 | 160 | 15,567 | 1,309 | n/a | 73 | 1,382 | 14,174 | 675 | n/a | 3,055 | 3,864 | 142.0 | 7.4 | 43.9 |
| 1983 | 15,456 | 526 | 1,117 | 185 | 19,928 | 1,495 | n/a | 67 | 1,562 | 16,767 | 593 | n/a | 2,853 | 3,446 | 148.3 | 8.4 | 46.3 |
| 1984 | 19,827 | 659 | 1,293 | 256 | 22,193 | 1,733 | n/a | 62 | 1,796 | 20,336 | 1,356 | n/a | 3,169 | 4,684 | 164.9 | 10.3 | 48.4 |
| 1985 | 19,264 | 682 | 1,709 | 384 | 21,988 | 2,248 | n/a | 76 | 2,324 | 19,664 | 1,445 | n/a | 2,754 | 4,288 | 155.3 | 11.9 | 51.1 |
| 1986 | 9,905 | 356 | 1,527 | 455 | 11,870 | 2,144 | n/a | 57 | 2,201 | 9,476 | 1,035 | n/a | 2,415 | 3,447 | 73.3 | 12.6 | 52.9 |
| 1987 | 9,513 | 359 | 1,593 | 533 | 12,004 | 2,137 | n/a | 65 | 2,162 | 10,282 | 809 | n/a | 2,044 | 2,863 | 81.7 | 12.4 | 55.7 |
| 1988 | 7,364 | 343 | 2,045 | 659 | 10,280 | 2,063 | n/a | 56 | 2,119 | 8,130 | 1,126 | n/a | 2,128 | 3,266 | 63.4 | 13.1 | 58.2 |
| 1989 | 7,214 | 272 | 2,167 | 547 | 10,220 | 2,333 | n/a | 57 | 2,390 | 7,833 | 1,182 | n/a | 2,638 | 3,817 | 51.1 | 14.2 | 63.6 |
| 1990 | 8,432 | 277 | 2,377 | 405 | 11,491 | 2,592 | n/a | 46 | 2,638 | 8,552 | 1,617 | n/a | 3,478 | 5,116 | 94.6 | 14.3 | 68.5 |
| 1991 | 7,771 | 385 | 2,569 | 476 | 11,420 | 3,296 | n/a | 66 | 3,364 | 8,073 | 1,566 | n/a | 5,101 | 7,067 | 85.0 | 15.9 | 73.0 |
| 1992 | 7,430 | 380 | 3,016 | 626 | 11,453 | 3,312 | n/a | 53 | 3,365 | 8,088 | 1,608 | n/a | 5,428 | 8,036 | 81.9 | 15.8 | 76.0 |
| 1993 | 8,110 | 523 | 3,569 | 699 | 12,899 | 3,661 | n/a | 47 | 3,708 | 9,191 | 1,213 | n/a | 4,661 | 5,874 | 95.9 | 16.0 | 78.0 |
| 1994 | 9,964 | 529 | 3,836 | 974 | 14,502 | 3,660 | n/a | 40 | 3,699 | 10,401 | 939 | 150 | 3,671 | 4,609 | 77.0 | 16.3 | 79.2 |
| 1995 | 9,881 | 514 | 4,141 | 1,166 | 15,702 | 3,913 | n/a | 37 | 3,950 | 11,852 | 1,088 | 204 | 4,388 | 5,440 | 81.1 | 16.3 | 81.4 |
| 1996 | 11,960 | 749 | 5,295 | 1,243 | 19,186 | 3,978 | n/a | 31 | 4,009 | 15,127 | 1,097 | 190 | 4,364 | 5,461 | 97.3 | 15.6 | 84.2 |
| 1997 | 10,327 | 703 | 5,254 | 1,279 | 17,563 | 4,150 | n/a | 34 | 4,184 | 13,377 | 1,154 | 191 | 4,263 | 5,417 | 87.4 | 16.7 | 86.6 |
| 1998 | 7,467 | 551 | 5,313 | 1,453 | 14,806 | 4,190 | n/a | 111 | 4,301 | 10,505 | 782 | 125 | 4,555 | 5,768 | 59.8 | 16.2 | 88.5 |
| 1999 | 10,267 | 727 | 5,031 | 1,436 | 17,460 | 4,249 | n/a | 382 | 4,631 | 12,830 | 487 | 66 | 3,063 | 3,620 | 93.0 | 13.7 | 90.9 |
| 2000 | 16,275 | 1,117 | 6,606 | 1,459 | 25,456 | 4,360 | n/a | 106 | 4,466 | 21,020 | 345 | 40 | 2,750 | 3,095 | 126.1 | 15.8 | 92.1 |
| 2001 | 13,646 | 963 | 8,140 | 1,436 | 24,186 | 4,347 | n/a | 49 | 4,396 | 19,789 | 420 | 34 | 3,670 | 4,090 | 125.7 | 19.0 | 94.1 |
| 2002 | 13,625 | 584 | 8,199 | 1,397 | 24,110 | 4,536 | n/a | 48 | 4,643 | 19,475 | 389 | 45 | 3,556 | 3,945 | 123.8 | 16.4 | 97.0 |
| 2003 | 13,366 | 1,136 | 7,554 | 1,539 | 23,602 | 4,496 | n/a | 8 | 4,504 | 19,098 | 334 | 42 | 3,412 | 3,746 | 130.9 | 17.4 | 100.0 |
| 2004 | 12,477 | 1,256 | 7,443 | 1,179 | 23,364 | 4,684 | 740 | 67 | 4,751 | 18,613 | 395 | 57 | 3,302 | 3,698 | 154.0 | 21.0 | 102.6 |
| 2005 | 15,656 | 1,584 | 8,502 | 1,451 | 28,893 | 5,113 | 412 | 128 | 5,241 | 23,452 | 460 | 34 | 4,371 | 4,831 | 215.9 | 27.6 | 104.9 |

**Notes**
(1) Revenues from pipelines and terminals, and other revenues of operators and production licensees
(2) Other costs of operators and production licensees not attributable to oil or gas fields
(3) Gross Operating Surplus = Total Income less Total Expenses
(4) E&A costs include Exploration and the cost of Appraisal wells drilled prior to development approval
The figures exclude change in stocks and book value of stocks

# United Kingdom

Medium-term forecasts derived from annual returns

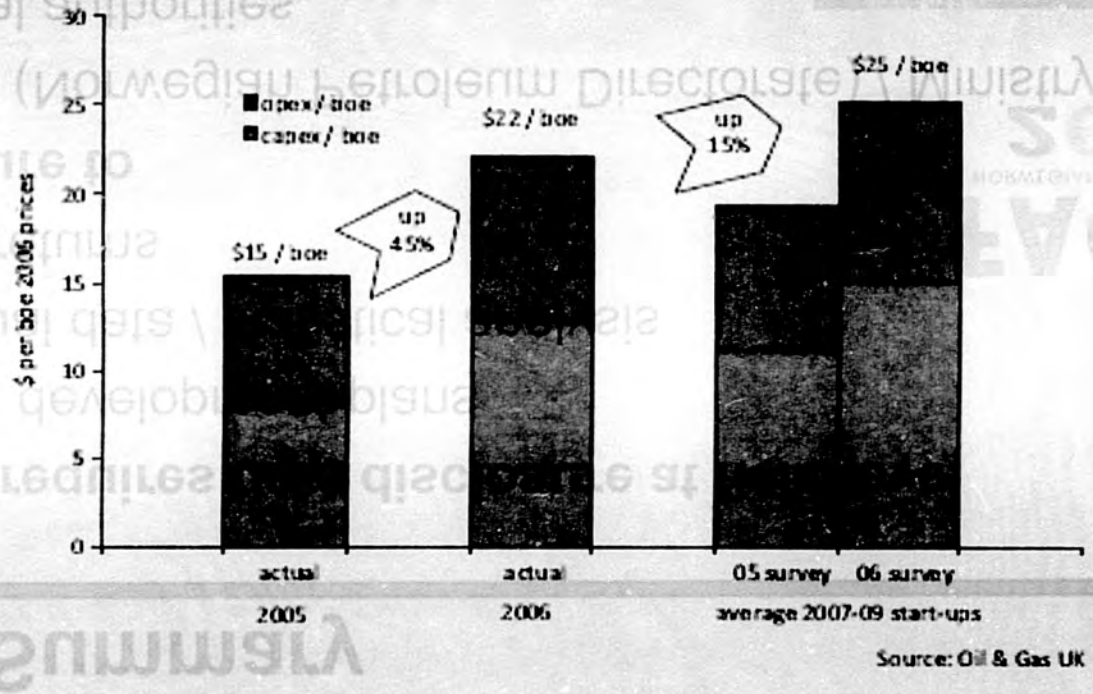
***Figure 30: UKCS Expenditure Forecast 2003-2010***



# United Kingdom

## Cost trends

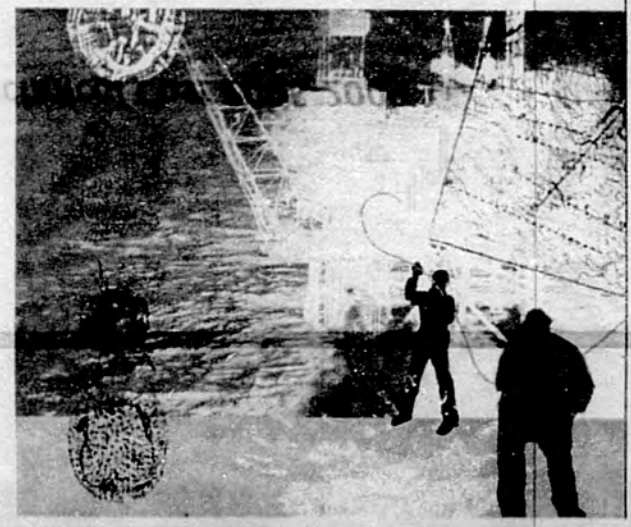
***Figure 33: UKCS New Developments' Unit Technical Cost 2005-2009***




Source: Oil & Gas UK

# Norway Summary

- **Norway requires data disclosure at field level**
  - Field development plans
  - Annual data / statistical analysis
  - Tax returns
- **Disclosure to**
  - NPD (Norwegian Petroleum Directorate) / Ministry
  - Fiscal authorities
- **Publication of aggregated information**



# Norway

## Field / discovery listing of resource volumes

**Tilstedeværende ressursar i felt**
*In-place resources in fields*

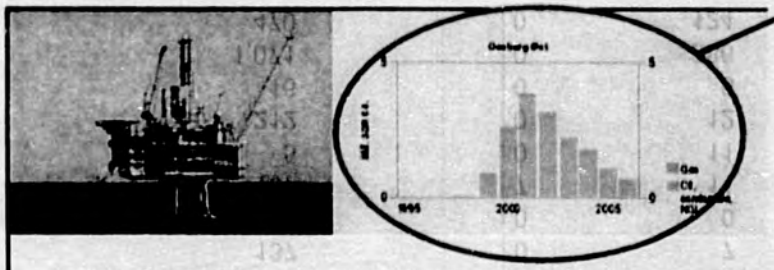
OLJEDIREKTORATET

| Felt | Olje mill Sm3 *Oil million Sm3* | Assosiert væske NGL/Kondensat mill Sm3 *Associated liquids million Sm3* | Assosiert gass mrd Sm3 *Associated gas (billion Sm3)* | Fri gass mrd Sm3 *Free gas billion Sm3* |
|---|---|---|---|---|
| ALBUSKJELL | 36 | 0 | 56 | 0 |
| ALVHEIM | 81 | 0 | 8 | 9 |
| BALDER | 137 | 0 | 7 | 0 |
| BLANE | 3 | 0 | 0 | 0 |
| BRAGE | 137 | 7 | 11 | 3 |
| COD | 5 | 0 | 11 | 0 |
| DRAUGEN | 212 | 0 | 12 | 0 |
| EDDA | 16 | 0 | 5 | 0 |
| EKOFISK | 1,071 | 0 | 286 | 0 |
| ELDFISK | 470 | 0 | 124 | 0 |
| EMBLA | 43 | 0 | 15 | 0 |
| ENOCH | 2 | 0 | 0 | 0 |
| FRAM | 58 | 0 | 8 | 8 |
| FRIGG | 0 | 1 | 0 | 150 |
| FRØY | 35 | 0 | 8 | 0 |
| GIMLE | 8 | 0 | 0 | 0 |
| GLITNE | 24 | 0 | 1 | 0 |
| GRANE | 209 | 0 | 3 | 0 |
| GULLFAKS | 583 | 0 | 69 | 0 |
| GULLFAKS SØR | 154 | 43 | 36 | 118 |

# Norway

Detail on field-by-field basis

*Production forecast by year*



## Oseberg Øst

| | |
|---|---|
| Block and production licence | Block 30/6 - production licence 053, awarded 1979 |
| Discovered | 1981 |
| Development approved | 11.10.1996 by the King in Council |
| On stream | 08.05.1999 |
| Operator | Norsk Hydro Produksjon AS |
| Licensees | Mobil Development Norway AS 4,70 % |
| | Norsk Hydro Produksjon AS 34,00 % |
| | Norske Conoco Phillips AS 2,40 % |
| | Petoro AS 38,00 % |
| | Statoil ASA 13,30 % |
| | Total E&P Norge AS 16,00 % |
| Recoverable reserves | Original: Remaining as of 31.12.2006: |
| | 37,8 million scm oil 11,7 million scm oil |
| | 0,4 billion scm gas |
| Production | Estimated production in 2007: |
| | Oil: 1,0 billion scm |
| Investment | Total investment is expected to be NOK 14,2 billion (2007 values) |
| | NOK 8,8 billion have been invested as of 31.12.2006 (2007 values) |
| Operating organisation | Bergen |
| Main supply base | Mongstad |

**Development:**
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 160 metres.

**Reservoir:**
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

**Recovery strategy:**
The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

**Transport:**
The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Sture terminal. The gas is mainly used for injection, gas lift and fuel.

**Status:**
Various measures for increased oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be set on stream in February 2008.

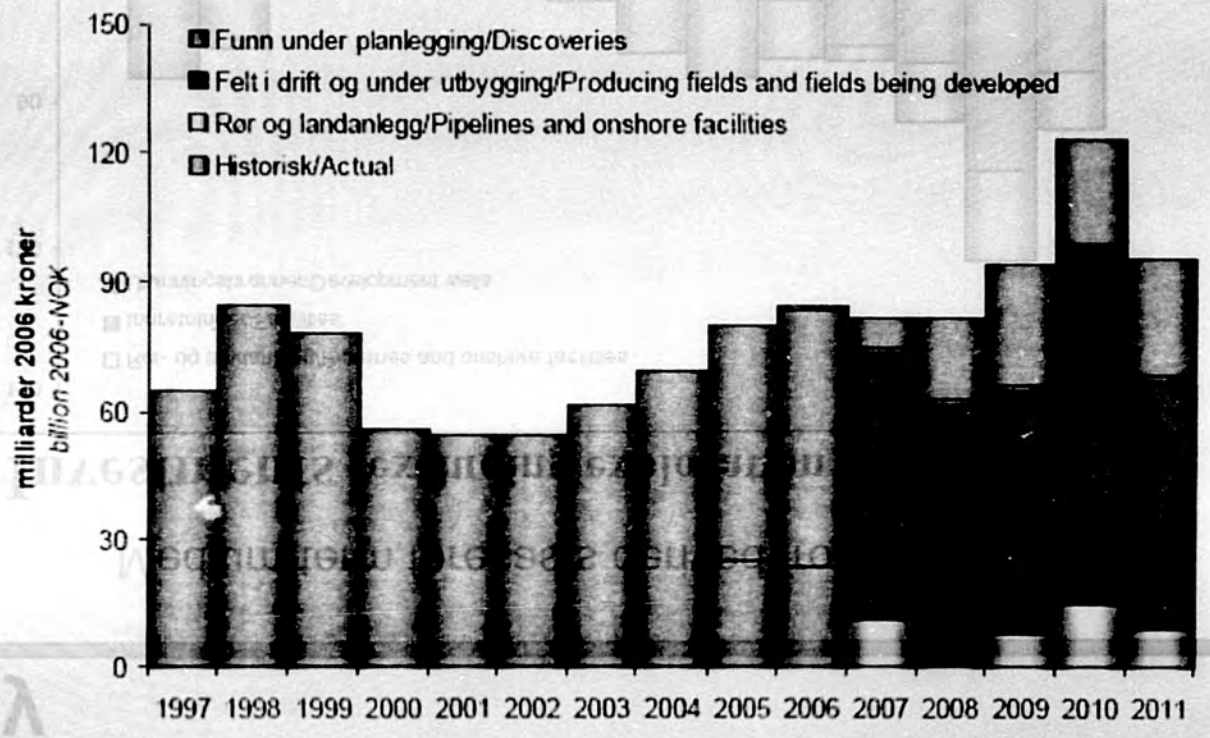
*Reserves and EUR*

*Total capital investment*
- *historical*
- *expected ultimate*

# Norway

Medium-term forecasts derived from annual returns

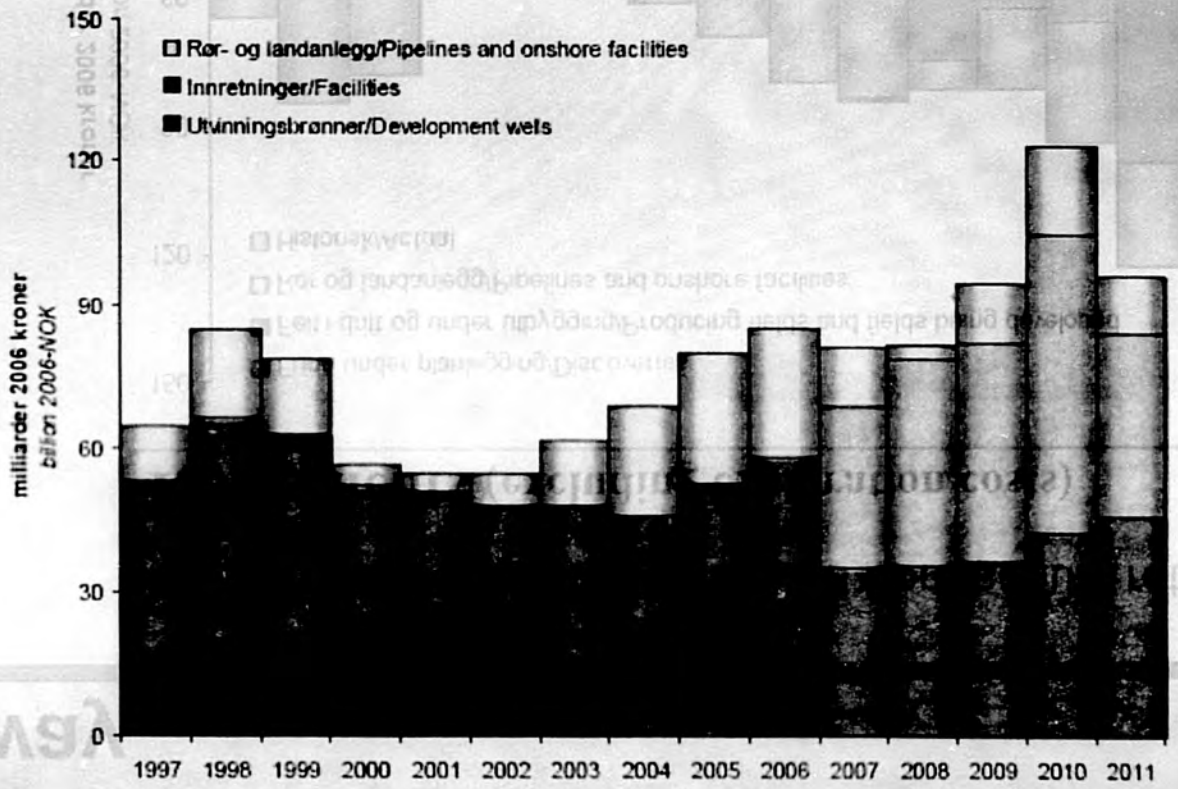
## Investments (excluding exploration costs)



# Norway

Medium-term forecasts derived from annual returns

## Investments (excluding exploration costs)



# Norway

Source of Investment

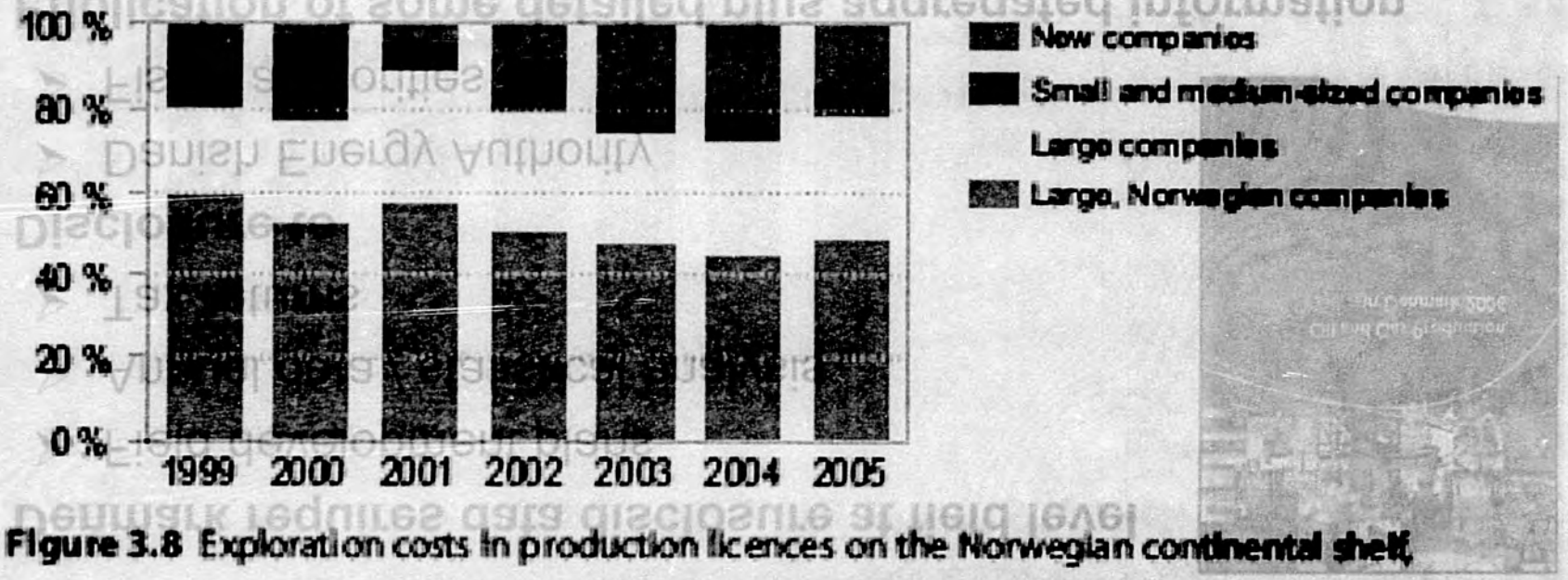



**Figure 3.8** Exploration costs in production licences on the Norwegian continental shelf, distributed according to the size of the companies

*(Source: Norwegian Petroleum Directorate)*

# Denmark Summary

- **Denmark requires data disclosure at field level**
  - Field development plans
  - Annual data / statistical analysis
  - Tax returns
- **Disclosure to**
  - Danish Energy Authority
  - Fiscal authorities
- **Publication of some detailed plus aggregated information**



# Denmark

## Field listing of annual capital investments .. both historical ..

Table 7.4 Investments, DKK million, nominal prices

| | 2002 | 2003 | 2004 | 2005 | 2006* |
|---|---|---|---|---|---|
| Cecilie | 223 | 660 | 309 | (18) | 4 |
| Dagmar | - | - | - | - | 148 |
| Dan | 437 | 943 | 750 | 750 | 684 |
| Gorm | 242 | 107 | 108 | 291 | 304 |
| Halfdan | 2,412 | 1,779 | 1,124 | 683 | 1,293 |
| Harald | 0 | 4 | 22 | 53 | 1 |
| Kraka | 3 | - | 2 | - | - |
| Nini | 285 | 1,288 | 319 | 163 | 19 |
| Roar | - | - | - | - | - |
| Rolf | - | 37 | 4 | - | 1 |
| Siri | 111 | 406 | 425 | 73 | 140 |
| Skjold | 5 | 77 | 8 | 11 | 4 |
| South Arne | 849 | 764 | 762 | 310 | 451 |
| Svend | 223 | - | - | - | - |
| Tyra | 85 | 305 | 459 | 1,020 | 1,520 |
| Tyra Southeast | 569 | 82 | 96 | 45 | - |
| Valdemar | (1) | 200 | 52 | 553 | 992 |
| NOGAT pipeline | - | 766 | 664 | 12 | - |
| Not allocated | 31 | (31) | 2 | 5 | 97 |
| Total | 5,475 | 7,386 | 5,105 | 3,951 | 5,658 |

*Estimate

# Denmark

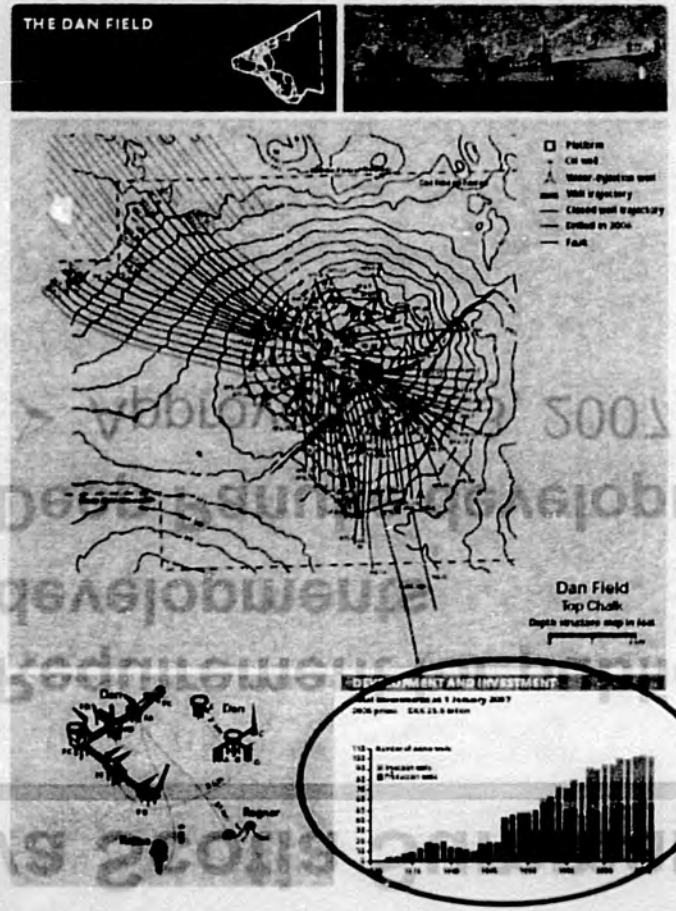
.. and projected

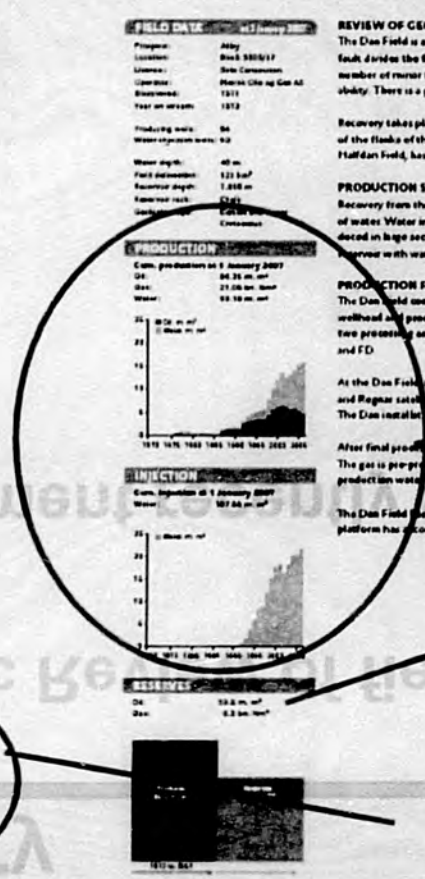
Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

| | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|
| **Ongoing and approved** | | | | | |
| Adda | - | 0.1 | 0.6 | - | - |
| Alma | - | 0.6 | 0.5 | - | - |
| Boje | - | - | - | 0.8 | - |
| Cecilie | - | - | - | - | - |
| Dagmar | - | - | - | - | - |
| Dan | 0.9 | 0.6 | - | - | - |
| Elly | 0.3 | 1.6 | - | - | - |
| Gorm | 0.1 | 0.0 | - | - | - |
| Halfdan | 2.0 | 0.9 | 0.1 | - | - |
| Harald | 0.0 | 0.1 | - | - | - |
| Kraka | 0.3 | - | - | - | - |
| Lulita | - | - | - | - | - |
| Nini | 0.1 | - | - | - | - |
| Regnar | - | - | - | - | - |
| Roar | - | - | - | - | - |
| Rolf | - | - | - | - | - |
| Siri | 0.3 | - | - | - | - |
| Skjold | - | - | - | - | - |
| South Arne | 0.8 | - | - | - | - |
| Svend | - | - | - | - | - |
| Tyra | 0.4 | 0.4 | 0.4 | 0.0 | 1.3 |
| Tyra Southeast | 0.5 | - | - | - | - |
| Valdemar | 1.6 | 0.7 | - | - | - |
| **Total** | **7.3** | **5.1** | **1.5** | **0.8** | **1.3** |
| | | | | | |
| Planned | - | - | - | - | 0.8 |
| Possible | - | 0.7 | 4.7 | 6.6 | 4.0 |
| **Expected** | **7.3** | **5.8** | **6.2** | **7.4** | **6.2** |

# Denmark

## Detail on field-by-field basis




*Production and injection history*

*Reserves and EUR*

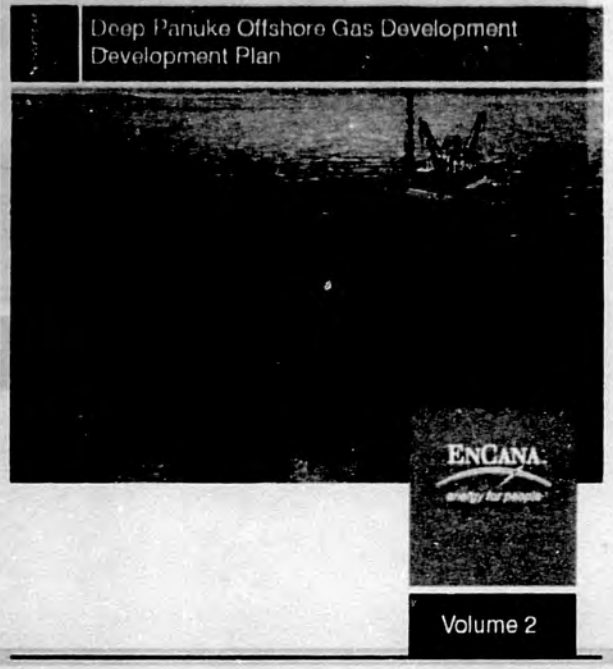
*Total capital investment and development drilling*

# Nova Scotia Summary

- **Requirement for public Review of field developments**
- **Deep Panuke development recently submitted**
  - Approved Oct 3, 2007



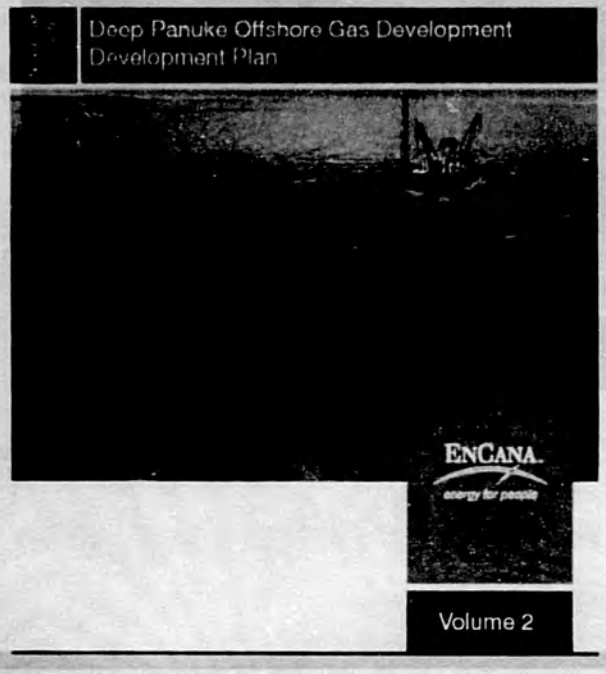
# Nova Scotia Deep Panuke




Includes sales gas forecast …

| Table 6.1 Sales Gas Forecast | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | P90 | | P50 | | P10 | | Mean | |
| | ($10^6$ sm3/d) | (MMscf/d) | ($10^6$ sm3/d) | (MMscf/d) | ($10^6$ sm3/d) | (MMscf/d) | ($10^6$ sm3/d) | (MMscf/d) |
| 2010 | 5.7 | 202 | 5.7 | 201 | 5.7 | 202 | 5.7 | 201 |
| 2011 | 8.5 | 300 | 8.4 | 300 | 8.5 | 300 | 8.5 | 300 |
| 2012 | 7.0 | 249 | 8.5 | 300 | 8.4 | 300 | 8.2 | 291 |
| 2013 | 4.5 | 159 | 6.4 | 228 | 8.4 | 300 | 6.2 | 219 |
| 2014 | 3.1 | 110 | 4.8 | 171 | 7.7 | 275 | 5.0 | 177 |
| 2015 | 2.2 | 79 | 3.8 | 136 | 6.0 | 213 | 4.0 | 143 |
| 2016 | 1.6 | 58 | 3.1 | 110 | 4.7 | 168 | 3.4 | 119 |
| 2017 | 1.3 | 45 | 2.5 | 90 | 4.1 | 145 | 2.7 | 97 |
| 2018 | 1.1 | 40 | 2.1 | 76 | 3.3 | 118 | 2.3 | 81 |
| 2019 | 0.0 | 0 | 1.6 | 58 | 2.9 | 103 | 1.9 | 67 |
| 2020 | 0.0 | 0 | 1.5 | 52 | 2.4 | 86 | 1.6 | 55 |
| 2021 | 0.0 | 0 | 1.5 | 52 | 2.1 | 73 | 1.3 | 47 |
| 2022 | 0.0 | 0 | 1.3 | 45 | 1.7 | 62 | 1.3 | 45 |
| 2023 | 0.0 | 0 | 1.1 | 40 | 1.6 | 55 | 1.1 | 41 |
| 2024 | 0.0 | 0 | 0.0 | 0 | 1.4 | 50 | 0.0 | 0 |
| 2025 | 0.0 | 0 | 0.0 | 0 | 1.4 | 51 | 0.0 | 0 |
| 2026 | 0.0 | 0 | 0.0 | 0 | 1.3 | 47 | 0.0 | 0 |
| 2027 | 0.0 | 0 | 0.0 | 0 | 1.2 | 41 | 0.0 | 0 |
| 2028 | 0.0 | 0 | 0.0 | 0 | 1.1 | 38 | 0.0 | 0 |

# Nova Scotia Deep Panuke




## … and cost forecast by expenditure type

### 6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPU, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.

| Table 6.2 Development Phase Expenditures | C$ Millions 2006 |
|---|---|
| EnCana Project Management & Engineering | 115 |
| Subsea | 135 |
| Export Pipeline | 200 |
| Drilling and Completions | 160 |
| *Subtotal:* | 610 |
| *Contingency* | 90 |
| **Total Cost to First Gas** | **700** |

**Annual operating costs, including the field centre (MOPU) lease, are estimated at $150 million per year, +/-25%.**

# Nova Scotia

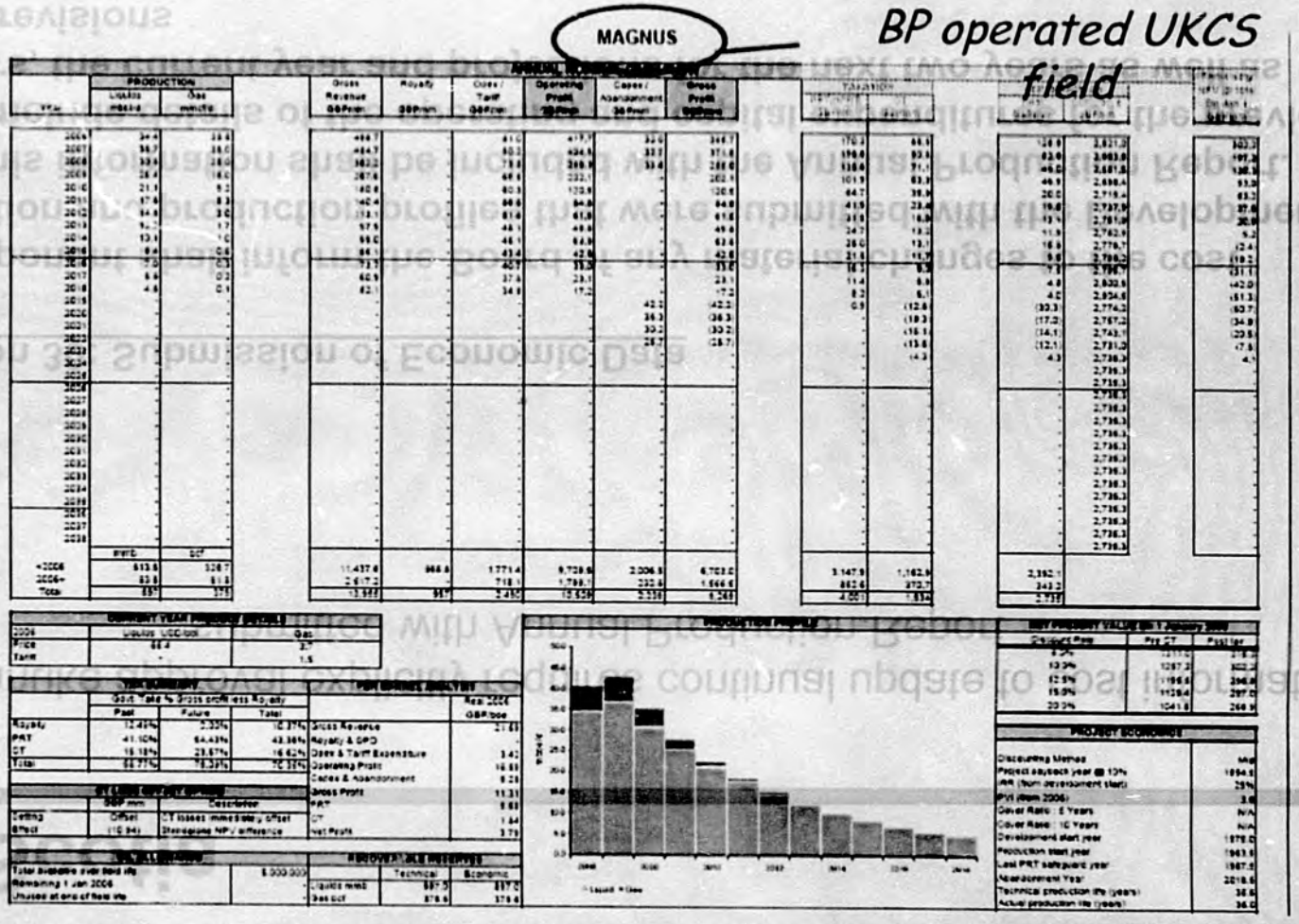
Deep Panuke approval explicitly requires continual update to cost information submitted with Annual Production Report

**Condition 30: Submission of Economic Data**

**The Proponent shall inform the Board of any material changes to the cost information and production profiles that were submitted with the Development Plan. This information shall be included with the Annual Production Report. This should include details of the operating and capital expenditures for the previous two years, the current year and projections for the next two years as well as reserve revisions**

# Publicly Available Sources

Example detailed field cashflow available from Deloitte's subscription service




Source: Deloitte Petroleum Services

GCA Gaffney, Cline & Associates Inc.
*Technical and Management Advisers to the Petroleum Industry Internationally Since 1962*
Principals
William B. Cline
Peter D. Gaffney

Four Oaks Place
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Email: gcah@gaffney-cline.com

RAR/jlm/C1492.00/gcah.292.07 October 19, 2007

# MEMORANDUM

**RE: Oil and Gas Reporting and Disclosure in Selected Countries**

As part of the review of its oil and gas fiscal system, the State of Alaska is exploring ways to improve the administration of its 'net' based taxes. Many believe the State is at a disadvantage to the oil companies in auditing their compliance as little data are routinely provided to the State. As such, Gaffney, Cline and Associates (GCA) has been asked to prepare a brief overview of how the acquisition, distribution and publication of oil company data are handled in other oil and gas producing regimes.

## SUMMARY

Provision by oil companies to host governments of detailed information pertaining to petroleum licenses and activities thereunder is routine around the world, usually as a condition of the license or contract under which the petroleum rights are granted. Certain data, including costs, may also be required (or covered, as well) by fiscal regulations governing different forms of taxation beyond general income tax provisions.

The information normally required to be provided encompasses the range from physical samples to activity plans and operating and financial data. The form of provision may vary, but formats consistent with electronic data exchange are developed for certain information. Where provided, data are generally at a well or field level of granularity.

Data provision is governed by various different confidentiality provisions, although sharing between different state/government entities appears more the standard than the exception. Basic geologic data are held confidential for periods of 2-5 years; although in some circumstances this may be as long as 10 years.

Data on fields under development and producing fields tend to either be released straight away, or are only released in aggregate form. For the most part, detailed data are only released on historical field or well production. Historical capital and operating cost data tend to be aggregated by country for disclosure, on an annual historical basis.

Limited amounts of data are also provided on a forecast basis. This is mixed between aggregated data and field-level data. Most of the field data so offered is reserves, but Denmark actually reports capital expenditure forecasts by field. No published forecast operating cost data has been identified.

Field data are typically submitted pursuant to two time-based criteria: at the time field exploration, appraisal or development plans are submitted, or a major revision to those plans is

incorporated, and on an annual basis for tracking and monitoring. Typically both situations will include production, capital and operating costs.

In its overview of reporting, GCA focused its efforts on reviewing practice in the petroleum producing countries of the North Sea, Canada, and Timor-Leste (where GCA recently assisted in the drafting of the Petroleum Act, the Petroleum Fiscal Act and associated regulations, drawing on "best practice" from around the world), although selected other examples are also included.

Considerable additional detail is available from websites and publications that go beyond the overview here, and should be studied further before detailed laws and regulations are drafted in Alaska.

## DISCUSSION

### Ownership of Data

Bar very minor exceptions, it is only in the United States that private entities own mineral rights. In Alaska, the state owns the rights to minerals making it similar to all other international locations.

States then lease or grant those rights to petroleum companies for a period of time either via a license, concession, service agreement or production sharing agreement. In exchange for receiving the rights to exploit (the state's) hydrocarbon resources, the oil companies are routinely obligated to provide the state with most, if not all, of the data related to their petroleum operations. The legislation, regulations and contracts in most countries specify quite clearly that the state owns all data obtained or produced as part of petroleum operations.

> *Timor-Leste shall have title to all data and information, whether raw, derived, processed, interpreted or analysed, obtained pursuant to any Authorisation.*

Some countries even go so far as to require that physical data, such as reservoir cores, are kept in-country at a state controlled facility.

> *Data and information acquired during the course of Petroleum Operations may be freely exported by Authorised Persons provided that the Ministry may require that an original, or in the case of a core, rock, fluid or other physical sample, a usable portion of the original, of all data and information, both physical and electronic, be kept in Timor-Leste.*

### Submission of Data

A variety of regulations usually stipulate the manner in which data are to be transmitted to the state. Physical data, such as cores or fluid samples, are packaged and labeled for long term storage. These are shipped to a facility designated by the state.

Other data, such as seismic, logs, production and costs, are supplied in two forms. First, the data are generally presented in the form of a routine report required by regulation. Reports are generally submitted in a non-editable format to ensure their integrity. Second, all data are

supplied in their 'raw' format, usually electronically, in a fully usable and editable format. Regulations sometimes prescribe how this is to be done.

> *Material and information which the licensee, operator, contractor etc. possesses or prepares in connection with planning and implementation of petroleum activities pursuant to this Act shall be available in Norway and may be required to be submitted free of charge to the Ministry or to anyone designated by the Ministry. Such material and information shall be submitted in a format decided by the Ministry to the extent this is deemed reasonable. In this connection, the Ministry may also require analyses and studies to be carried out.*

**Types of Data**

As noted earlier, most states maintain ownership to all data acquired in the course of petroleum operations. This data is then supplied to the state. The amount of data coming in is not inconsequential and can add up fast.

Appendix I is a list of the types of data typically supplied to the state. It is by no means exhaustive or complete but is meant to be a representation of what is available.

Once obtained, information may be designated as confidential or commercially sensitive. Depending on the nature of the data, it may be kept confidential for a period of time, usually 5 to 10 years.

| Data Type | Data Acquisition Entity | Concessionaire |
|---|---|---|
| Seismic data | 10 years | 5 years |
| Magneto metric / Gravimetric data | 10 years | 5 years |
| Geochemical data | 10 years | 5 years |
| Well data | 2 years | 2 years |

*Example shown is from Brazil*

**Publication and Public Access**

There is some variance in what a state chooses or is allowed to publish. The World Bank-led initiative on transparency (the Extractive Industries Transparency Initiative) has many countries rethinking their approach, but for the most part, countries still tend to keep most data confidential or aggregated at a level so as to prevent any identification of individual pieces.

There are a couple of exceptions. Timor-Leste recently passed legislation that is probably the most transparent of any government. By law the energy ministry in Timor-Leste is obligated to publish or make available to the public:

*(i) copies of all Authorisations and amendments thereto, whether or not terminated;*
*(ii) copies of all unitisation agreements;*
*(iii) summaries of Authorisations (and amendments thereto, whether or not terminated) and unitisation agreements;*
*(iv) approved Development Plans;*

*(v) all assignments and other dealings consented to in respect of Authorisations, subject to commercial confidence as to the commercial terms;*

*(vi) all exemptions granted from, or agreeing to a variation or suspension of, the conditions of an Authorization;*

*(vii) all such reports from companies acting in compliance with requirements under the Act and Authorisations in such manner and detail as required by their Authorisation and as provided by regulation; and*

*(viii) all such reports by Authorised Persons on payments relating to Petroleum Operations made to the Government of Timor-Leste as are required by law.*

The last item makes public all data (i.e. production rates, capital and operating costs) related to the calculation of royalty, production share and profit oil.

Brazil, in an indirect manner, provides the means by which a knowledgeable person can ascertain the operating costs per company per field.

*The Brazilian petroleum regulatory agency displays regularly in its web site price, production, royalties and windfall profit tax on a field-by-field basis. Based on this it is possible to assess, indirectly, the production cost of a given field. Once the windfall profit tax is known it is possible to calculate the taxable basis. By deducting the taxable basis from gross revenue minus royalties, the balance is total costs (capital plus operating).*

**North Sea Countries' Reporting**

All four of the key North Sea jurisdictions (United Kingdom (UK), Norway, Denmark and Netherlands) have regulations and practices requiring companies to disclose information on a detailed basis. This information includes well and seismic data, plus detailed development plans / updates including production, capital and operating cost forecasts and annual updates / forecasts of the same information.

While the information is supplied by the companies on a detailed, field-by-field (or where required, well-by-well) basis, public reporting is much less detailed. Typically data will be aggregated on a country-wide basis, although in some cases life-of-field numbers (reserves, costs) may be reported. The main exception to this is historical production data, which is generally available on a detailed basis.

Costs reported for regulatory purposes are typically at a field level, and exclude overheads and other non-field allocated costs. Such costs would typically be incorporated in tax filings, and be governed by taxpayer confidentiality.

While not official government data, all North Sea countries have had available very good subscription-service data on a field-by-field basis. The services typically include full annual historic and forecast production, capital and operating cost data, and field economics. While the data sources incorporate all official public releases (from the state to official company publications), they also benefit from "guidance" from the companies themselves. In the latter cases, while not wanting to warrant data or even acknowledge its release, the companies find it useful to see that it is reasonable as they themselves are consumers of the data sets on fields in which they do not have an interest.

The impact of these services is such that they are relied on heavily by investors and planners alike. While no substitute for official data, they have proven to be a significant driver of activity whereby new players can gain a good understanding of participants, the nature of oil and gas fields, and costs prior to entering an area.

Availability of such reporting has now spread to several countries in the world, although the accuracy of data may be variable from country to country, and subject to local considerations regarding allowing data release.

**UK**

The UK has significant regulations covering requirements for the provision of data. This is captured at a field level, both at the time of a Field Development Plan submission (and major revision), plus on an annual or semi-annual survey basis. While collected by the Department of Trade and Industry (DTI), and shared amongst Crown (Government) bodies, disclosure is more limited.

Detailed information is made publicly available on well / field production data. However, both cost (capital and operating) and fiscal (tax and royalty receipts) are disclosed only on an aggregate basis. There are some exceptions where detailed data is provided to persons or commercial organizations undertaking studies for Government bodies; however these are provided under conditions of confidentiality and the underlying detail is not disclosed in the final report.

Supplementary detail provided in Appendix II shows the regulations and format of information provision, and examples of disclosure (with the actual numbers generally being available in tabular format as well).

**Denmark**

Denmark receives detailed field-by-field production and cost data on an annual basis, although it has not standardized reporting by operator, reflecting principally that it only has five operators in the country.

Public disclosure and reporting provides a mix of detail. Country summaries of historic and forecast data are provided, but so is investment detail on a field by field basis, (See Appendix III).

In addition, though, field by field summaries are provided which provide a good background on historic, though limited future data.

Operating costs, on the other hand, are only reported on an aggregate basis.

**Norway**

Norway requires operators to provide detailed field production, capital and operating cost forecasts as part of a development plan, and on an annual basis. Operators are required to submit detailed production and cost forecasts each year in spreadsheet form to the Norwegian Petroleum Directorate (NPD) (See Appendix IV).

Each year the NPD will produce a long report on operations on the Norwegian Continental Shelf, with a lot of production and cost data provided in aggregate form. In addition, however, field summaries are also provided showing reserves and capital (expected total and remaining) for both producing fields and fields in development. No annual-time series is available, although analysis of several years' reports will allow a historic time-series to be developed on a field-by-field basis.

Operating cost data is available only on a consolidated basis, as are statistics on government revenues from royalties and taxes.

**Netherlands**

The Netherlands publishes similar information to the other North Sea countries with regard to production data, although it tends to aggregate it on a license basis, thereby covering possibly several fields rather than a single field. Resource estimates are published with an onshore/offshore split, but not at a field or license detail level.

Historical fiscal revenues are detailed, but no cost information is readily discernable.

Such information is provided to EBN, a state-owned oil and gas company that is a partner in all oil ad gas licenses. However, detailed information of all types is considered commercially confidential and not disclosed publicly.

**Canada (Nova Scotia and Newfoundland-Labrador)**

Canada divides jurisdiction for oil and gas between the Provinces and Federal government. The Western Provinces of Alberta, British Colombia and Saskatchewan each administer their own regimes, while Frontier Lands and the Maritimes operate jointly with the Federal government.

Nova Scotia and Newfoundland-Labrador have similar, though separate, regimes with many common provisions, operating under join boards (Canada-Nova Scotia Offshore Petroleum Board, and Canada Newfoundland-Labrador Offshore Petroleum Board).

The Provinces have strict hard-copy and electronic formatting requirements for all technical data submissions. Detailed by field production reports are filed (and disclosed on a monthly basis) in addition to a weekly progress report of all activities in licensed areas.

The Provinces' Petroleum Boards are required to conduct a Public Review of the Development unless the Board determines a review is not necessary in the public interest. The guidelines for the contents of the Development Plan are relatively comprehensive.

An example of the information disclosure from the proposed development plan for Nova Scotia's Deep Panuke field that is currently under consideration, and providing production forecasts and indicative costs, is shown in Appendix V. Similar disclosure was made previously for the Sable Island Gas Project.

An example of the data disclosure requirements in Newfoundland-Labrador is given in Appendix VI.

In addition to the comprehensive submission and disclosure requirements for the development plan, both Atlantic Canada Provinces mandate public disclosure of all well and geological data after specified periods between 2 and 5 years depending on the type of information.

Attachments

Appendices

| | | |
|---|---|---|
| I: | Types of Data |
| II: | UK Detail |
| III: | Denmark Detail |
| IV: | Norway Detail |
| V: | Nova Scotia Detail |
| VI: | Newfoundland-Labrador Detail |

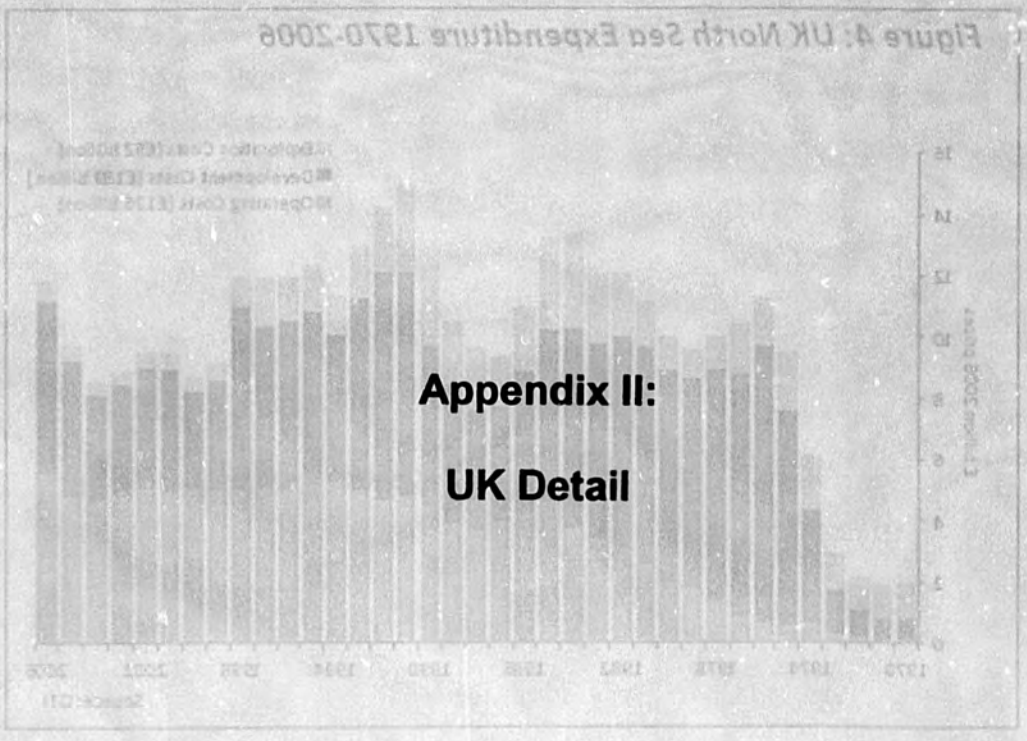
# APPENDICES

# TYPES OF DATA

- **EXPLORATION AND APPRAISAL**
  - Joint Operating Agreements
  - Work Programs and Budgets
  - Seismic
  - Daily Drilling Reports
  - Logs
  - Well tests
  - Geological Models and Maps
- **DEVELOPMENT**
  - Development Plans with Opex and Capex Projections
  - Contracts
  - Construction Progress Reports
  - Drilling Reports
  - Reservoir Characterization
- **PRODUCTION**
  - Work Programs and Budgets
  - Sales, Revenues and Pricing
  - Transportation Agreements
  - Sales Contracts
  - Production
  - Injection
  - Opex (as spent and forecast)
  - Capex (as spent and forecast)
  - Facility Maps and Studies
  - Safety and Environmental reports
  - Training and Development
- **ABANDONMENT**
  - Abandonment Plan and Budget
  - Progress Reports
  - Environmental Clean-up Assessment

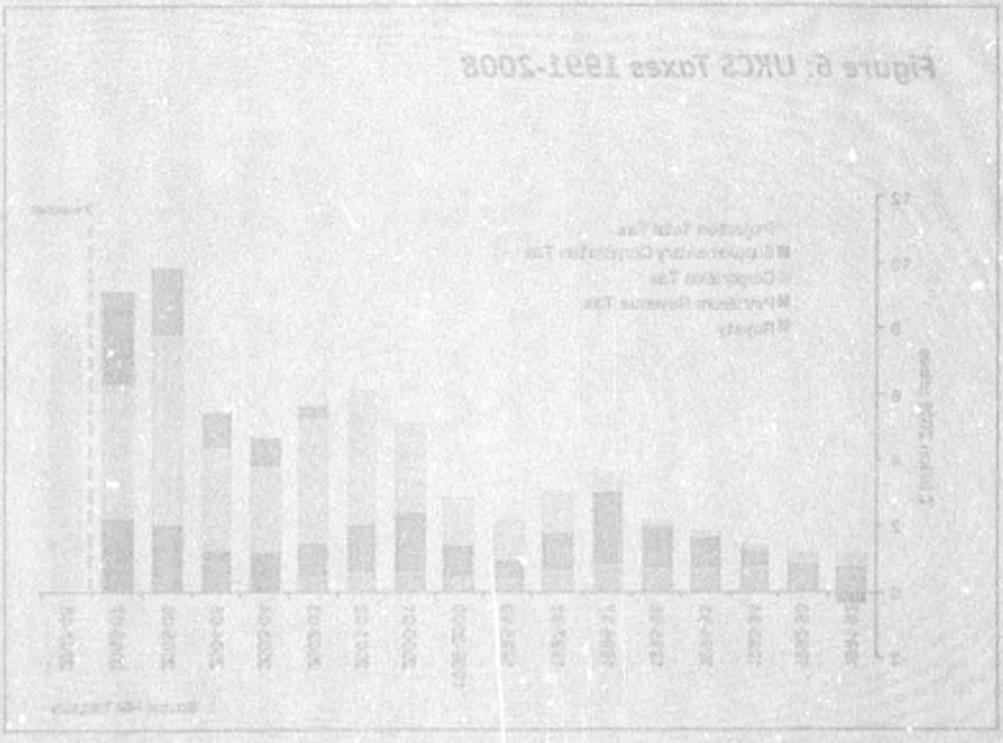
# Appendix I:

# Types of Data

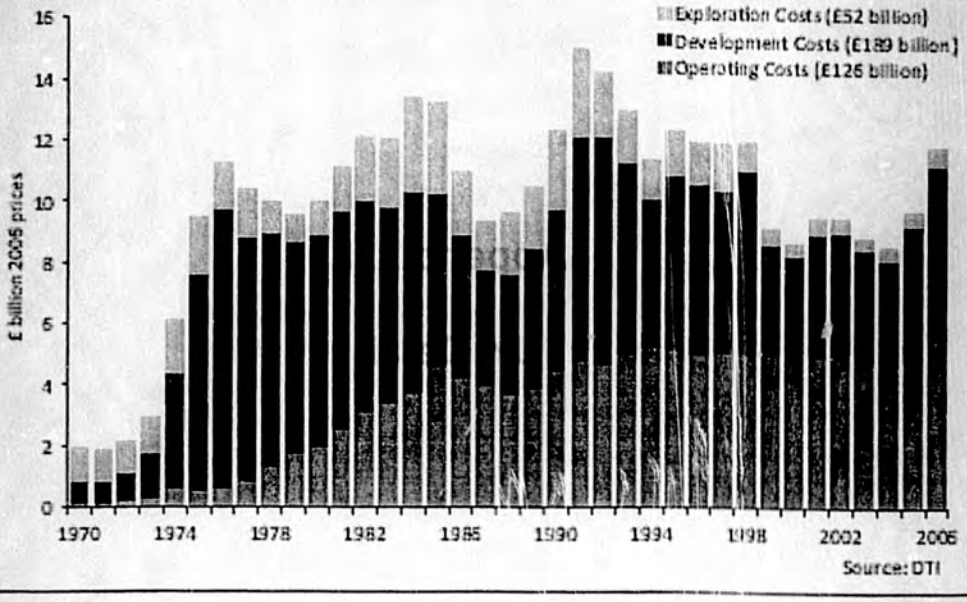


# Appendix II:

# UK Detail



## Figure 4: UK North Sea Expenditure 1970-2006




## Figure 6: UKCS Taxes 1991-2008

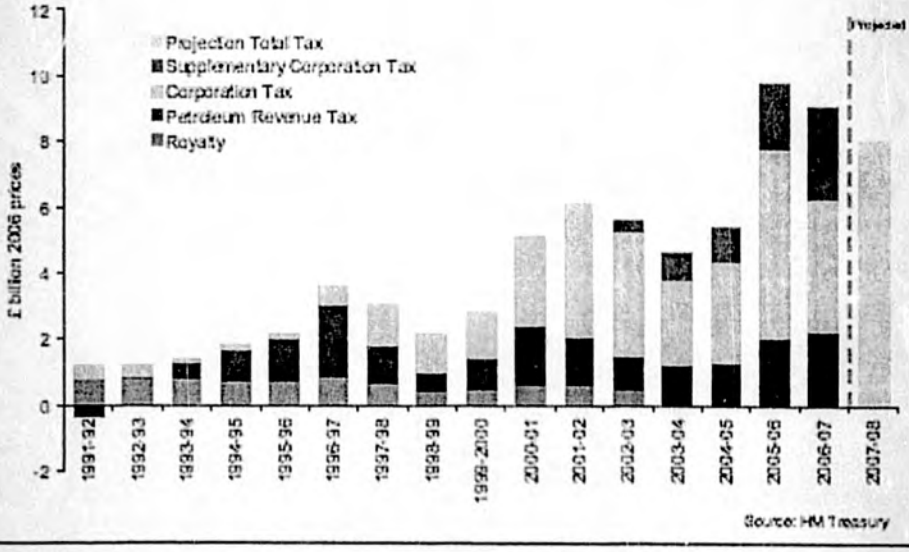
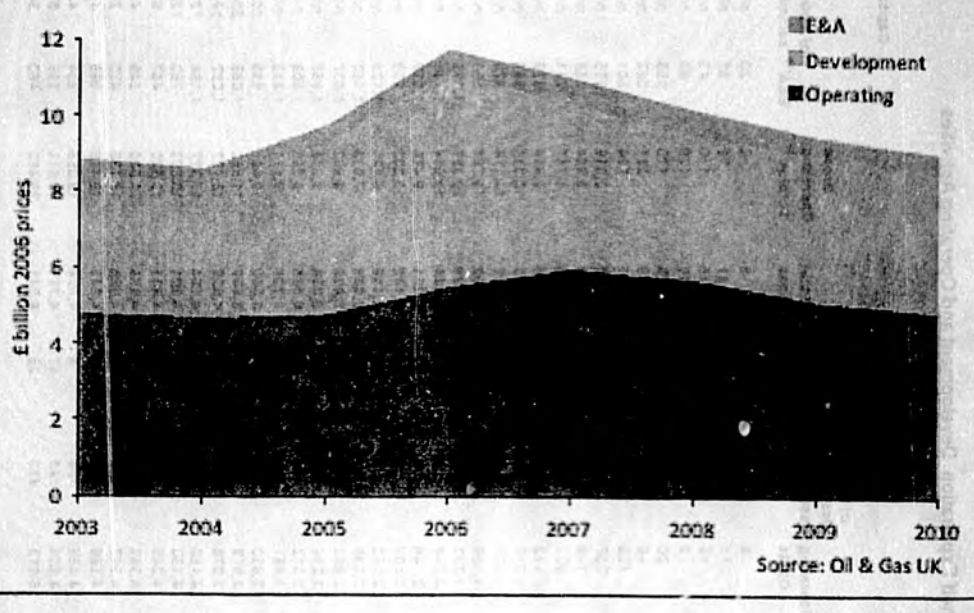


**Figure 30: UKCS Expenditure Forecast 2003-2010**



## Income from and Expenditure on UK Continental Shelf Exploration, Development and Operating Activities

(£ million)

| | Income | | | | | Expenses | | | | | Capital Expenditure | | | | Prices | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil Sales | NGL Sales | Gas Sales | Other Income[1] | Total Income | Operating Costs | *of which decommissioning costs* | Other expenses[2] | Total Expenses | Gross Operating Surplus[3] | E&A[4] | *of which seismic* | Investment other than E&A | Total | Average Oil Price (£/tonne) | Average Gas Price (p/therm) | GDP Deflator (2005=100) |
| 1970 | 0 | 0 | 0 | 4 | 5 | 6 | n/a | 0 | 6 | -2 | 20 | n/a | 53 | 73 | n/a | n/a | 9.9 |
| 1971 | 0 | 0 | 60 | 8 | 68 | 11 | n/a | 0 | 11 | 78 | 57 | n/a | 72 | 129 | n/a | n/a | 10.8 |
| 1972 | 0 | 1 | 114 | 9 | 124 | 15 | n/a | 0 | 15 | 110 | 43 | n/a | 112 | 164 | n/a | n/a | 11.7 |
| 1973 | 0 | 2 | 133 | 11 | 146 | 18 | n/a | 0 | 18 | 129 | 69 | n/a | 215 | 284 | n/a | n/a | 12.6 |
| 1974 | 0 | 3 | 166 | 21 | 190 | 20 | n/a | 0 | 20 | 170 | 153 | n/a | 554 | 707 | n/a | n/a | 14.4 |
| 1975 | 43 | 15 | 190 | 29 | 277 | 46 | n/a | 0 | 46 | 231 | 342 | n/a | 1,274 | 1,616 | n/a | n/a | 18.3 |
| 1976 | 624 | 21 | 258 | 21 | 924 | 130 | n/a | 0 | 130 | 794 | 301 | n/a | 2,070 | 2,372 | n/a | 1.8 | 21.1 |
| 1977 | 2,197 | 29 | 317 | 20 | 2,562 | 207 | n/a | 0 | 207 | 2,356 | 375 | n/a | 2,107 | 2,482 | n/a | 2.1 | 24.0 |
| 1978 | 2,771 | 35 | 432 | 12 | 3,250 | 346 | n/a | 0 | 346 | 2,904 | 281 | n/a | 2,170 | 2,451 | n/a | 3.1 | 26.8 |
| 1979 | 5,641 | 53 | 538 | 44 | 6,276 | 502 | n/a | 18 | 519 | 5,757 | 241 | n/a | 2,064 | 2,305 | n/a | 3.8 | 30.7 |
| 1980 | 8,719 | 132 | 547 | 82 | 9,480 | 692 | n/a | 34 | 726 | 8,854 | 379 | n/a | 2,768 | 2,767 | n/a | 4.8 | 36.7 |
| 1981 | 12,206 | 135 | 643 | 114 | 13,298 | 1,017 | n/a | 45 | 1,063 | 12,235 | 550 | n/a | 2,647 | 3,387 | n/a | 5.5 | 40.8 |
| 1982 | 14,129 | 312 | 956 | 160 | 15,557 | 1,309 | n/a | 73 | 1,382 | 14,174 | 675 | n/a | 3,059 | 3,934 | 142.0 | 7.4 | 43.9 |
| 1983 | 15,456 | 529 | 1,117 | 156 | 16,328 | 1,495 | n/a | 67 | 1,562 | 15,767 | 993 | n/a | 2,853 | 3,846 | 145.3 | 8.4 | 46.3 |
| 1984 | 19,927 | 659 | 1,290 | 255 | 22,133 | 1,733 | n/a | 62 | 1,795 | 20,338 | 1,395 | n/a | 3,189 | 4,584 | 164.9 | 10.0 | 48.4 |
| 1985 | 19,204 | 692 | 1,709 | 384 | 21,988 | 2,248 | n/a | 76 | 2,324 | 19,664 | 1,445 | n/a | 2,754 | 4,239 | 159.3 | 11.9 | 51.1 |
| 1986 | 8,909 | 386 | 1,927 | 455 | 11,678 | 2,144 | n/a | 57 | 2,201 | 9,476 | 1,039 | n/a | 2,419 | 3,457 | 73.3 | 12.6 | 52.9 |
| 1987 | 9,513 | 358 | 1,990 | 533 | 12,394 | 2,107 | n/a | 55 | 2,162 | 10,232 | 809 | n/a | 2,044 | 2,853 | 81.7 | 12.4 | 55.7 |
| 1988 | 7,084 | 249 | 2,046 | 689 | 10,208 | 2,060 | n/a | 58 | 2,118 | 8,120 | 1,129 | n/a | 2,129 | 3,258 | 63.4 | 13.1 | 59.2 |
| 1989 | 7,214 | 272 | 2,197 | 547 | 10,220 | 2,330 | n/a | 57 | 2,386 | 7,833 | 1,182 | n/a | 2,635 | 3,817 | 61.1 | 14.2 | 63.7 |
| 1990 | 7,432 | 277 | 2,377 | 405 | 11,491 | 2,992 | n/a | 46 | 2,038 | 8,552 | 1,637 | n/a | 3,478 | 5,116 | 94.6 | 14.3 | 66.5 |
| 1991 | 7,576 | 385 | 2,958 | 476 | 11,428 | 3,296 | n/a | 58 | 3,354 | 8,073 | 1,955 | n/a | 5,101 | 7,067 | 85.0 | 15.9 | 73.0 |
| 1992 | 7,430 | 380 | 3,015 | 626 | 11,463 | 3,312 | n/a | 53 | 3,365 | 8,098 | 1,508 | n/a | 5,428 | 6,936 | 81.9 | 15.8 | 76.0 |
| 1993 | 6,110 | 523 | 3,558 | 699 | 12,890 | 3,651 | n/a | 47 | 3,708 | 9,191 | 1,213 | n/a | 4,661 | 5,874 | 65.9 | 15.0 | 78.0 |
| 1994 | 8,964 | 528 | 3,836 | 974 | 14,302 | 3,860 | n/a | 40 | 3,900 | 10,401 | 939 | 150 | 3,671 | 4,609 | 77.0 | 16.3 | 79.2 |
| 1995 | 9,881 | 614 | 4,141 | 1,166 | 15,802 | 3,913 | n/a | 37 | 3,950 | 11,852 | 1,086 | 204 | 4,255 | 5,440 | 81.1 | 16.3 | 81.4 |
| 1996 | 11,850 | 749 | 5,295 | 1,243 | 19,136 | 3,978 | n/a | 31 | 4,009 | 15,127 | 1,057 | 190 | 4,364 | 5,481 | 97.3 | 16.6 | 84.2 |
| 1997 | 10,327 | 700 | 5,254 | 1,279 | 17,561 | 4,150 | n/a | 34 | 4,184 | 13,377 | 1,164 | 151 | 4,263 | 5,457 | 87.4 | 15.7 | 86.6 |
| 1998 | 7,467 | 551 | 5,313 | 1,453 | 14,806 | 4,150 | n/a | 111 | 4,301 | 10,503 | 762 | 125 | 4,996 | 5,768 | 59.8 | 16.2 | 88.9 |
| 1999 | 10,257 | 727 | 5,031 | 1,436 | 17,460 | 4,249 | n/a | 282 | 4,531 | 12,920 | 457 | 55 | 3,063 | 3,520 | 80.0 | 13.7 | 90.9 |
| 2000 | 15,275 | 1,117 | 6,605 | 1,488 | 25,486 | 4,360 | n/a | 106 | 4,466 | 21,020 | 345 | 40 | 2,750 | 3,096 | 138.1 | 15.8 | 92.1 |
| 2001 | 13,546 | 993 | 8,140 | 1,435 | 24,186 | 4,347 | n/a | 49 | 4,396 | 19,789 | 420 | 34 | 3,570 | 3,990 | 125.7 | 19.0 | 94.1 |
| 2002 | 13,629 | 894 | 8,199 | 1,397 | 24,118 | 4,536 | n/a | 48 | 4,643 | 19,475 | 389 | 46 | 3,598 | 3,988 | 123.8 | 18.4 | 97.0 |
| 2003 | 13,365 | 1,105 | 7,564 | 1,538 | 23,582 | 4,496 | n/a | 8 | 4,504 | 19,056 | 334 | 42 | 3,412 | 3,746 | 130.0 | 17.4 | 100.0 |
| 2004 | 13,477 | 1,256 | 7,443 | 1,178 | 23,364 | 4,564 | 148 | 67 | 4,781 | 18,613 | 356 | 57 | 3,302 | 3,658 | 154.0 | 21.0 | 102.6 |
| 2005 | 15,556 | 1,684 | 8,502 | 1,451 | 29,893 | 5,113 | 412 | 128 | 5,241 | 23,452 | 460 | 34 | 4,371 | 4,831 | 215.8 | 27.6 | 104.9 |

**Notes**

(1) Revenues from pipelines and terminals, and other revenues of operators and production licensees.
(2) Other costs of operators and production licensees not attributable to oil or gas fields.
(3) Gross Operating Surplus = Total Income less Total Expenses.
(4) E&A costs include Exploration and the cost of Appraisal wells drilled prior to development approval.
The figures exclude change in stocks and book value of stocks.

| Well No: | Field Name: | Operator: | Company contact: Contact details : | | Date: | | CONVERSION FACTOR | | Please indicate barrel:tonne and scf:therm conversion factors |
|---|---|---|---|---|---|---|---|---|---|
| | Type of development: | | | | | | Oil | | |
| Discovery date: | | | | | | | NGL | | |
| Depth: | | | | | | | Gas | | |

| | | | | | | | | | | | Costs | | £ million (constant 2007 prices) | | | | TARIFFS | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Production | | | Sales | | | Other oil/gas uses | | | | CAPEX | | | OPEX | | | Tariff Expenditure/Income | | | | | |
| Year | Oil 000 tonnes | NGLs 000 tonnes | Gas million therms | Oil 000 tonnes | NGLs 000 tonnes | Gas million therms | Gas Flaring million therms | Re-injection million therms | Fuel use 000 tonnes | Other oil/gas usage apart from sales (please specify) | Exploration and Appraisal Drilling | Development Drilling expenditure | Other Capital expenditure | Operating expenditure (excluding tariff payments and lease costs) | Lease Costs (FPSOs etc) | Decommissioning Costs | Oil £/tonne | NGL £/tonne | Gas p/therm | Tariff payment to third parties £ million | Tariff receipts from old fields £ million | Tariff receipts new fields £ million |
| Previous spend 1997 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 1998 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 1999 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2000 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2001 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2002 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2003 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2004 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2005 | | | | | | | | | | | | | | | | | | | | | | |
| Previous spend 2006 | | | | | | | | | | | | | | | | | | | | | | |
| Already committed in 2007 | | | | | | | | | | | | | | | | | | | | | | |
| other 2007 | | | | | | | | | | | | | | | | | | | | | | |
| 2008 | | | | | | | | | | | | | | | | | | | | | | |
| 2009 | | | | | | | | | | | | | | | | | | | | | | |
| 2030 | | | | | | | | | | | | | | | | | | | | | | |
| 2031 | | | | | | | | | | | | | | | | | | | | | | |
| TOTAL | | | | | | | | | | | | | | | | | | | | | | |

| List Licensees and give % holding within field | | Gas Contract information: |
|---|---|---|
| EXPORT ROUTE | | Premium/discount to Brent Crude: Please indicate using plus or minus $ per barrel or p/therm |
| Oil | | |
| NGL | | Notes: |
| Gas | | |

Once complete please send to field team coordinator by email

*Example of spreadsheet form of data to be submitted with Field Development Plan or update.*

# Appendix III:

# Denmark Detail

Table 7.4 Investments, DKK million, nominal prices

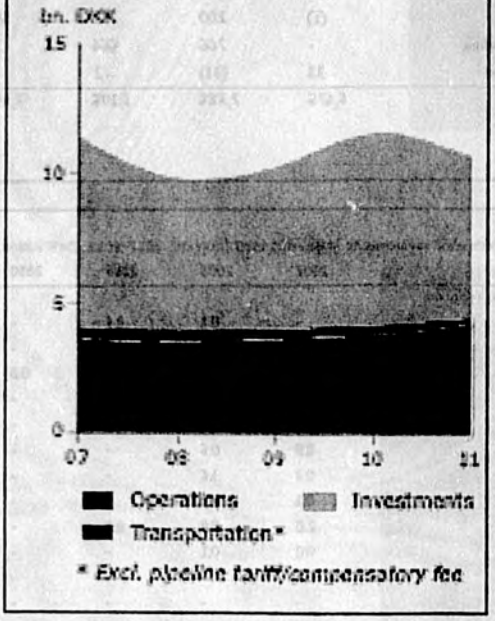
| | 2002 | 2003 | 2004 | 2005 | 2006* |
|---|---|---|---|---|---|
| Cecilie | 223 | 660 | 309 | (18) | 4 |
| Dagmar | - | - | - | - | 168 |
| Dan | 437 | 943 | 750 | 750 | 684 |
| Gorm | 242 | 107 | 108 | 291 | 304 |
| Halfdan | 2,412 | 1,779 | 1,124 | 683 | 1,293 |
| Harald | 0 | 4 | 22 | 53 | 1 |
| Kraka | 3 | - | 2 | - | - |
| Nini | 285 | 1,268 | 319 | 163 | 19 |
| Roar | - | - | - | - | - |
| Rolf | - | 37 | 4 | - | 1 |
| Siri | 111 | 406 | 435 | 73 | 140 |
| Skjold | 5 | 77 | 8 | 11 | 4 |
| South Arne | 849 | 764 | 762 | 310 | 451 |
| Svend | 223 | - | - | - | - |
| Tyra | 85 | 305 | 459 | 1,000 | 1,520 |
| Tyra Southeast | 569 | 82 | 96 | 45 | - |
| Valdemar | (1) | 200 | 52 | 553 | 992 |
| NOGAT pipeline | - | 766 | 664 | 12 | - |
| Not allocated | 31 | (31) | 2 | 5 | 97 |
| Total | 5,475 | 7,386 | 5,105 | 3,951 | 5,658 |

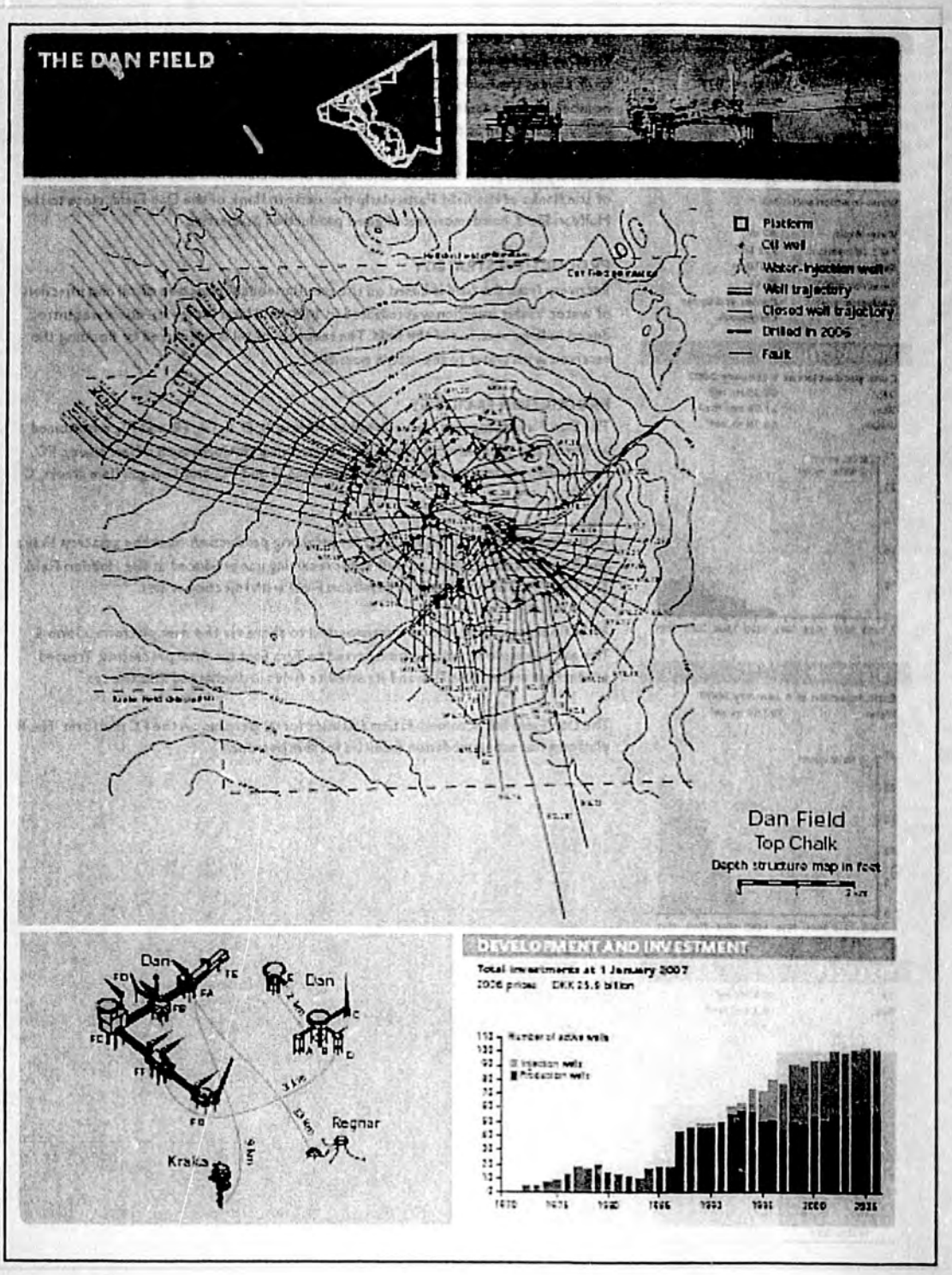
*Estimate

Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

| | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|
| Ongoing and approved | | | | | |
| Adda | - | 0.1 | 0.6 | - | - |
| Alma | - | 0.6 | 0.5 | - | - |
| Boje | - | - | - | 0.8 | - |
| Cecilie | - | - | - | - | - |
| Dagmar | - | - | - | - | - |
| Dan | 0.9 | 0.6 | - | - | - |
| Elly | 0.3 | 1.6 | - | - | - |
| Gorm | 0.1 | 0.0 | - | - | - |
| Halfdan | 2.0 | 0.9 | 0.1 | - | - |
| Harald | 0.0 | 0.1 | - | - | - |
| Kraka | 0.3 | - | - | - | - |
| Lulita | - | - | - | - | - |
| Nini | 0.1 | - | - | - | - |
| Ragnar | - | - | - | - | - |
| Roar | - | - | - | - | - |
| Rolf | - | - | - | - | - |
| Siri | 0.3 | - | - | - | - |
| Skjold | - | - | - | - | - |
| South Arne | 0.8 | - | - | - | - |
| Svend | - | - | - | - | - |
| Tyra | 0.4 | 0.4 | 0.4 | 0.0 | 1.3 |
| Tyra Southeast | 0.5 | - | - | - | - |
| Valdemar | 1.6 | 0.7 | - | - | - |
| Total | 7.3 | 5.1 | 1.5 | 0.8 | 1.3 |
| Planned | - | - | - | - | 0.8 |
| Possible | - | 0.7 | 4.7 | 6.6 | 4.0 |
| Expected | 7.3 | 5.8 | 6.2 | 7.4 | 6.2 |

**Fig. 7.5** Investments in fields, operating and oil transportation costs, 2006 prices




THE DAN FIELD
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2006
Fault
Dan Field
Top Chalk
Depth structure map in feet
Dan
Dan
Regnar
Kraka
DEVELOPMENT AND INVESTMENT

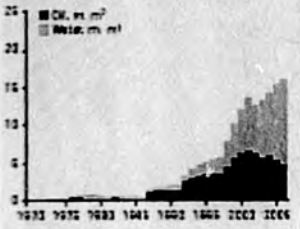
## FIELD DATA

| | |
|---|---|
| Prospect: | Abby |
| Location: | Block 5506/17 |
| Licence: | Sole Concession |
| Operator: | Maersk Olie og Gas AS |
| Discovered: | 1971 |
| Year on stream: | 1972 |
| Producing wells: | 56 |
| Water injection wells: | 50 |
| Water depth: | 40 m |
| Field delineation: | 121 km² |
| Reservoir depth: | 1,850 m |
| Reservoir rock: | Chalk |
| Geological age: | Danian and Upper Cretaceous |

## PRODUCTION

Cum. production at 1 January 2007

| | |
|---|---|
| Oil: | 88.35 m. m³ |
| Gas: | 21.06 bn. Nm³ |
| Water: | 53.15 m. m³ |




## INJECTION

Cum. injection at 1 January 2007

| | |
|---|---|
| Water: | 197.66 m. m³ |




## RESERVES

| | |
|---|---|
| Oil: | 93.6 m. m³ |
| Gas: | 6.3 bn. Nm³ |



### REVIEW OF GEOLOGY

The Dan Field is an anticlinal structure induced partly due to salt tectonics. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap in the field.

Recovery takes place from the central part of the Dan Field and from large sections of the flanks of the field. Particularly the western flank of the Dan Field, close to the Halfdan Field, has demonstrated good production properties.

### PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1989, and later water injection was introduced in large sections of the field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

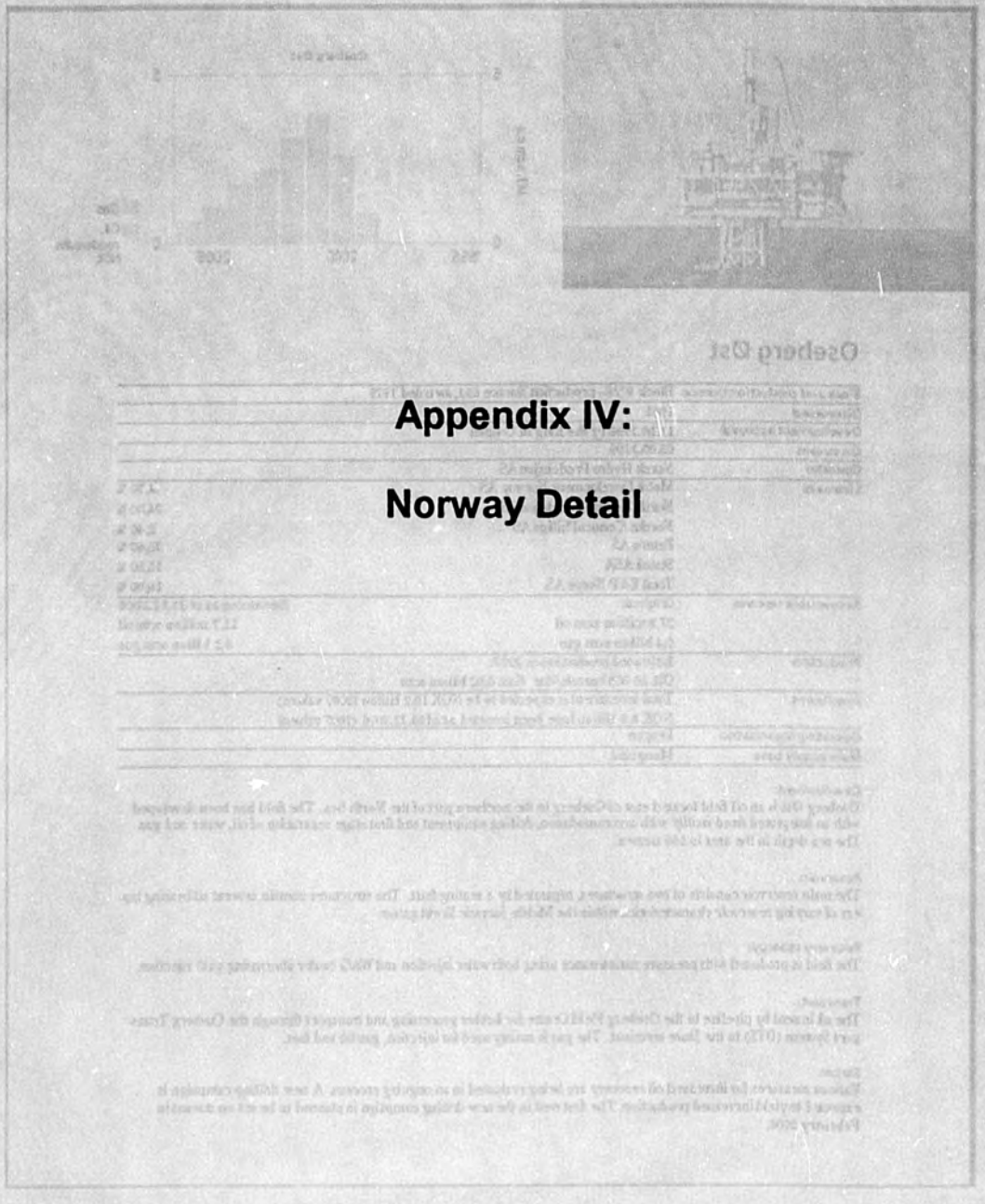
### PRODUCTION FACILITIES

The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

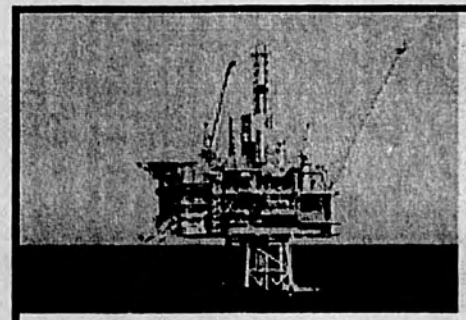
After final processing, the oil is transported to shore via the riser platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

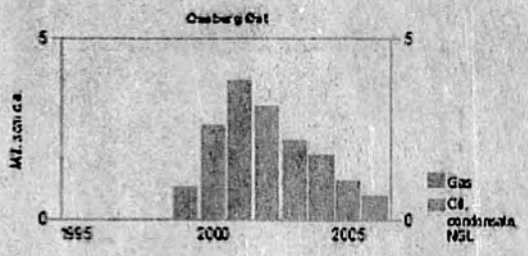
The Dan Field has accommodation facilities for 97 persons on the FC platform. The B platform has accommodation facilities for five persons.



# Appendix IV:

# Norway Detail






## Oseberg Øst

| | | |
|---|---|---|
| Block and production licence | Block 30/6 - production licence 053, awarded 1979 | |
| Discovered | 1981 | |
| Development approval | 11.10.1996 by the King in Council | |
| On stream | 03.05.1999 | |
| Operator | Norsk Hydro Produksjon AS | |
| Licensees | Mobil Development Norway AS | 4,70 % |
| | Norsk Hydro Produksjon AS | 34,00 % |
| | Norske ConocoPhillips AS | 2,40 % |
| | Petoro AS | 33,60 % |
| | Statoil ASA | 15,00 % |
| | Total E&P Norge AS | 10,00 % |
| Recoverable reserves | Original: | Remaining as of 31.12.2006 |
| | 27,8 million scm oil | 11,7 million scm oil |
| | 0,4 billion scm gas | 0,2 billion scm gas |
| Production | Estimated production in 2007: | |
| | Oil 10 000 barrels/day Gas: 0,02 billion scm | |
| Investment | Total investment is expected to be NOK 10,2 billion (2007 values) | |
| | NOK 8,8 billion have been invested as of 31.12.2006 (2007 values) | |
| Operating organisation | Bergen | |
| Main supply base | Mongstad | |

Development:
Oseberg Øst is an oil field located east of Oseberg in the northern part of the North Sea. The field has been developed with an integrated fixed facility with accommodation, drilling equipment and first stage separation of oil, water and gas. The sea depth in the area is 160 metres.

Reservoir:
The main reservoir consists of two structures, separated by a sealing fault. The structures contain several oil-bearing layers of varying reservoir characteristics within the Middle Jurassic Brent group.

Recovery strategy:
The field is produced with pressure maintenance using both water injection and WAG (water alternating gas) injection.

Transport:
The oil is sent by pipeline to the Oseberg Field Centre for further processing and transport through the Oseberg Transport System (OTS) to the Sture terminal. The gas is mainly used for injection, gas lift and fuel.

Status:
Various measures for increased oil recovery are being evaluated in an ongoing process. A new drilling campaign is expected to yield increased production. The first well in the new drilling campaign is planned to be set on stream in February 2008.

# Appendix V:

# Nova Scotia Detail

# (from Deep Panuke Development Plan)

| Table 6.1 Sales Gas Forecast | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Year | P90 | | P50 | | P10 | | Mean | |
| | ($10^6$ sm3/d) | (MMscfd) | ($10^6$ sm3/d) | (MMscfd) | ($10^6$ sm3/d) | (MMscfd) | ($10^6$ sm3/d) | (MMscfd) |
| 2010 | 5.7 | 202 | 5.7 | 201 | 5.7 | 202 | 5.7 | 201 |
| 2011 | 8.5 | 300 | 8.4 | 300 | 8.5 | 300 | 8.5 | 300 |
| 2012 | 7.0 | 249 | 8.5 | 300 | 8.4 | 300 | 8.2 | 291 |
| 2013 | 4.5 | 159 | 6.4 | 228 | 8.4 | 300 | 6.2 | 219 |
| 2014 | 3.1 | 110 | 4.8 | 171 | 7.7 | 275 | 5.0 | 177 |

### 6.3.1 Development Phase Expenditures

Estimates for the development phase include costs incurred by EnCana, as operator of the Project, from the fourth quarter 2006 to first gas production, scheduled to occur in the fourth quarter of 2010.

The costs shown in Table 6.2 are for the M&NP option, and exclude any costs associated with the MOPU, which will be included as operating costs payable during the production life of the Project.

The SOEP Subsea Option would see a reduction in the cost of the export pipeline during the Development Phase. However, there would be an increase in operating costs for tariffs charged as a result of using the SOEP pipeline. At this time, these costs are not defined.

| Table 6.2 Development Phase Expenditures | C$ Millions 2006 |
|---|---|
| EnCana Project Management & Engineering | 115 |
| Subsea | 135 |
| Export Pipeline | 200 |
| Drilling and Completions | 160 |
| *Subtotal:* | 610 |
| *Contingency* | 90 |
| **Total Cost to First Gas** | 700 |

# Appendix VI:

# Newfoundland-Labrador Detail

## 3.14 GUIDELINES FOR DEVELOPMENT PLAN (PART II)

Part II of the Development Plan should consist of the studies, analyses and evaluations, or other information and proposals, in support of Part I of the Plan. In accordance with the Acts, proprietary information provided in Part II will not be disclosed without the proponent's consent.

The Acts also require that petrophysical, fluid, core and well testing data, analyses and evaluations, be provided to the Board for reasons other than as part of the Development Plan submission. If the proponent wishes to rely on this material to support the Development Plan, the material should be referenced explicitly but need not be resubmitted. The confidentiality status of such information will be determined in accordance with the relevant provisions of the Acts.

The following are to be provided where applicable and when available:

- geological studies;
- geophysical studies;
- petrophysical studies;
- reservoir engineering studies, including rock and fluid data and analyses, and reservoir simulation studies;
- original oil and gas-in-place and recoverable reserves studies;
- production engineering information and studies;
- field hydraulic studies;
- production and transportation systems studies;
- environmental studies and analyses;
- plans for waste treatment and disposal;
- development cost data and economic analyses of alternatives;
- information related to matters of conservation, safety of operations and pollution prevention; and,
- any other studies that were used in support of the Development Plan.