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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

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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;*

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- (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.

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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).

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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 and 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 Columbia 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 joint 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.

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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

**Appendix I:
Types of Data**

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 II:

UK Detail

Figure 4: UK North Sea Expenditure 1970-2006

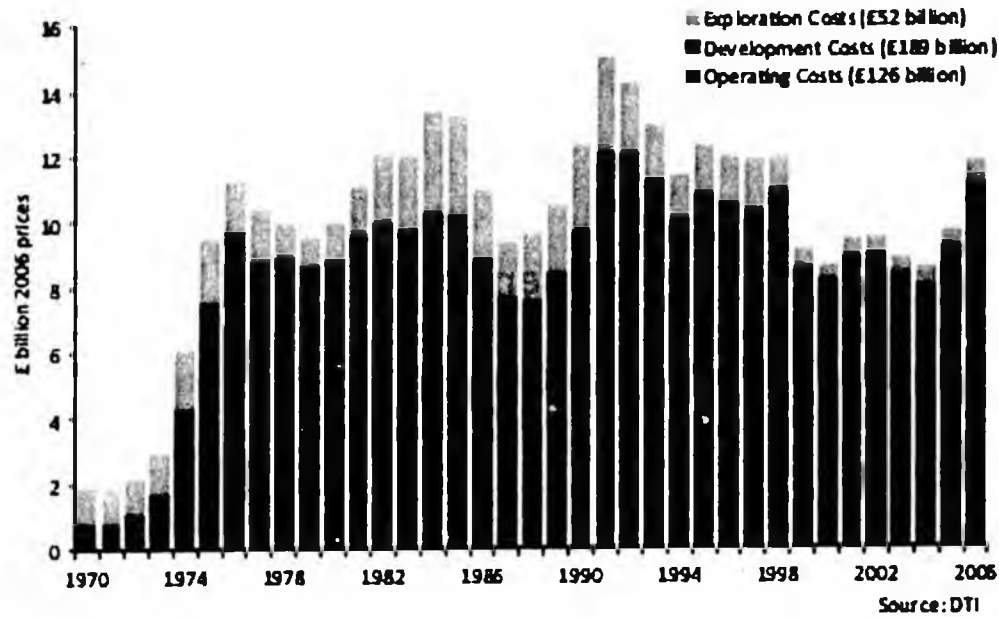


Figure 6: UKCS Taxes 1991-2008

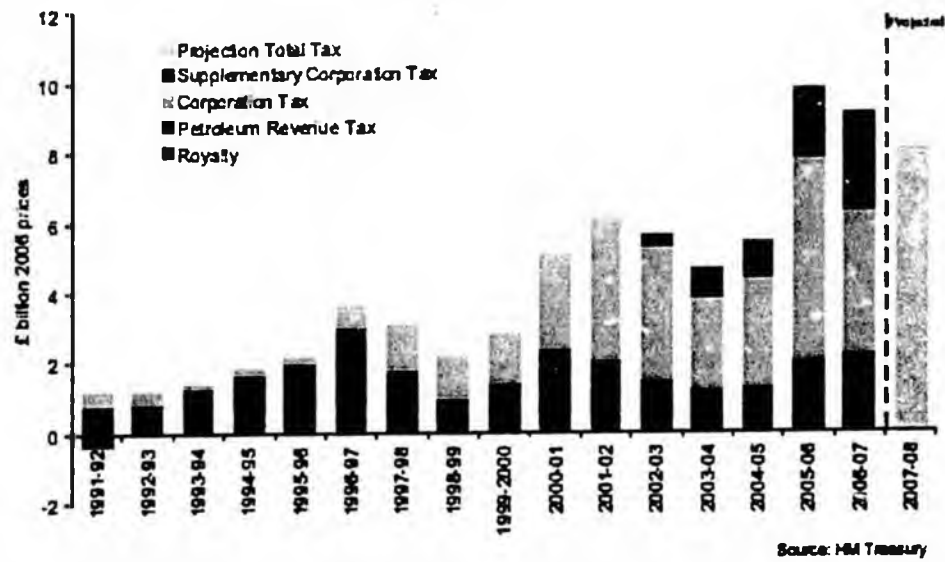
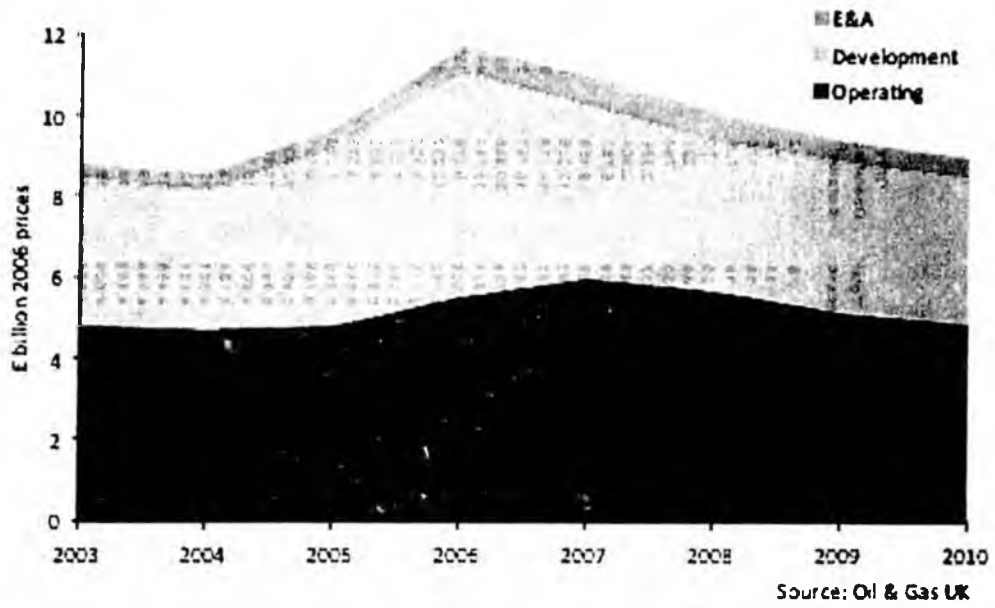


Figure 30: UKCS Expenditure Forecast 2003-2010



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⁾	EBA ⁽⁴⁾	of which seismic	Investment other than EBA	Total	Average Oil Price (£/tonne)	Average Gas Price (£/therm)	ODF Dollars (2005=100)
1970	0	0	3	4	6	6	n/a	0	6	-2	33	n/a	53	73	n/a	n/a	9.9
1971	0	0	83	8	88	1	n/a	0	11	76	57	n/a	72	128	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	148	18	n/a	0	18	129	69	n/a	215	284	n/a	n/a	12.5
1974	0	3	166	21	190	20	n/a	0	20	170	153	n/a	544	787	n/a	n/a	14.4
1975	43	15	190	29	277	45	n/a	0	45	231	242	n/a	1,374	1,610	n/a	n/a	18.3
1976	524	21	258	21	824	133	n/a	0	133	794	301	n/a	2,070	2,872	n/a	1.8	21.1
1977	2,197	20	317	23	2,662	237	n/a	0	237	2,366	375	n/a	2,107	2,482	n/a	2.1	24.0
1978	2,771	35	432	12	3,266	346	n/a	0	346	2,904	261	n/a	2,170	2,481	n/a	3.1	25.8
1979	5,641	53	539	44	6,278	502	n/a	18	519	5,757	241	n/a	2,044	2,866	n/a	3.8	30.7
1980	8,719	132	647	82	9,580	592	n/a	34	728	8,854	379	n/a	2,384	2,787	n/a	4.9	36.7
1981	12,306	135	843	114	13,298	1,317	n/a	45	1,663	12,235	659	n/a	2,847	3,387	n/a	6.5	40.5
1982	14,129	312	955	152	15,567	1,339	n/a	73	1,882	14,174	875	n/a	3,059	3,884	142.3	7.4	43.9
1983	16,496	529	1,117	189	18,329	1,495	n/a	67	1,662	16,767	993	n/a	2,652	3,648	148.3	8.4	46.3
1984	19,327	659	1,293	256	22,183	1,733	n/a	62	1,795	20,338	1,395	n/a	3,159	4,584	164.9	10.3	48.4
1985	19,204	692	1,709	384	21,989	2,249	n/a	76	2,824	19,564	1,445	n/a	2,794	4,288	158.3	11.9	51.1
1986	8,309	386	1,927	455	11,077	2,144	n/a	57	2,201	9,476	1,039	n/a	2,415	3,667	73.3	12.6	52.9
1987	9,513	358	1,983	533	12,388	2,107	n/a	55	2,162	10,232	809	n/a	2,044	2,863	81.7	12.4	55.7
1988	7,084	249	2,046	659	10,238	2,063	n/a	54	2,118	8,120	1,125	n/a	2,126	3,268	63.4	13.1	59.2
1989	7,214	272	2,187	547	10,220	2,332	n/a	57	2,888	7,833	1,182	n/a	2,535	3,817	51.1	14.2	63.6
1990	8,432	277	2,377	425	11,481	2,892	n/a	46	2,938	9,562	1,617	n/a	3,475	5,118	84.6	14.3	65.5
1991	7,578	385	2,998	476	11,428	3,296	n/a	58	3,864	8,373	1,955	n/a	5,101	7,867	85.0	15.9	73.0
1992	7,430	382	3,016	525	11,460	3,312	n/a	53	3,865	8,368	1,504	n/a	5,428	8,884	81.9	15.8	75.0
1993	8,110	523	3,558	599	12,800	3,551	n/a	47	3,768	9,181	1,213	n/a	4,661	8,874	85.8	15.3	78.0
1994	8,964	528	3,835	874	14,202	3,563	n/a	40	3,809	10,431	939	100	3,671	4,880	77.3	16.3	79.2
1995	9,981	614	4,141	1,155	15,892	3,513	n/a	37	3,869	11,852	1,088	204	4,255	5,448	81.1	16.3	81.4
1996	11,850	749	5,295	1,243	19,188	3,978	n/a	31	4,009	15,127	1,057	190	4,364	5,481	87.3	15.6	84.2
1997	10,327	700	5,254	1,279	17,561	4,153	n/a	34	4,184	13,377	1,154	191	4,263	5,487	87.4	16.7	86.6
1998	7,487	551	5,313	1,453	14,806	4,130	n/a	111	4,881	10,533	762	125	4,956	5,768	59.8	16.2	88.9
1999	10,247	727	5,031	1,435	17,460	4,249	n/a	262	4,681	12,820	457	55	3,083	3,628	82.3	13.7	90.9
2000	16,275	1,117	6,005	1,498	25,488	4,363	n/a	106	4,469	21,020	349	40	2,750	3,888	138.1	15.8	92.1
2001	13,545	953	8,143	1,435	24,186	4,347	n/a	49	4,388	19,799	420	34	3,570	3,888	125.7	16.3	94.1
2002	13,629	894	8,189	1,387	24,110	4,596	n/a	48	4,643	19,475	349	45	3,598	3,888	123.9	15.4	97.0
2003	13,365	1,138	7,554	1,338	23,802	4,495	n/a	8	4,604	19,282	334	42	3,412	3,748	130.0	17.4	100.0
2004	13,477	1,255	7,443	1,175	23,864	4,564	748	87	4,751	18,513	395	57	3,302	3,888	184.0	21.3	102.8
2005	16,656	1,684	8,502	1,451	28,088	5,113	472	125	6,241	23,452	463	34	4,371	4,881	215.8	27.6	104.9

Notes

- (1) Revenues from oilfields 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) EBA 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.

Field No:	Field Name:	Operator:	Company contact:	Date:	CONVERSION FACTOR	Please indicate barrel/tonne and perform conversion factor															
	Contact details:				Oil																
Summary data:	Time of development:				NGL																
Output:					Gas																
										Costs (£ million (constant 2007 prices))											
										TARIFFS											
Production			Sales			Other oil/gas uses			CAPEX			OPEX				Tariff Expenditures					
Oil BBL tonnes	NGL BBL tonnes	Gas million therms	Oil BBL tonnes	NGL BBL tonnes	Gas million therms	Gas Flaring million therms	Re- injection million therms	Fuel use BBL 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 payments to third parties £ million	Tariff receipts from old fields £ million	Tariff receipts new fields £ million
Year																					
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																					
Previously committed in 2007																					
other 2007																					
2008																					
2009																					
2010																					
2011																					
TOTAL																					
List Licenses and give % holding within field			Gas Contract Information:																		
EXPORT ROUTE			Premium/discount to Brent Crude:																		
Oil			Please indicate using plus or minus \$ per barrel or p/therm																		
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

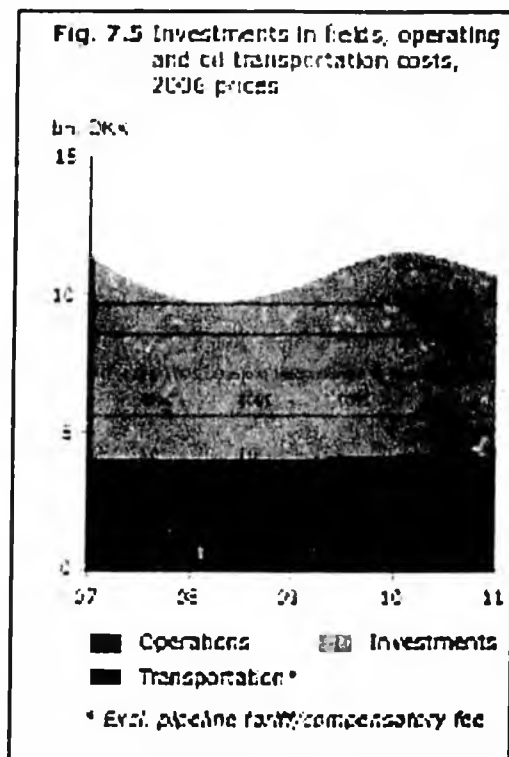
Table 7.4 Investments, DKK million, nominal prices

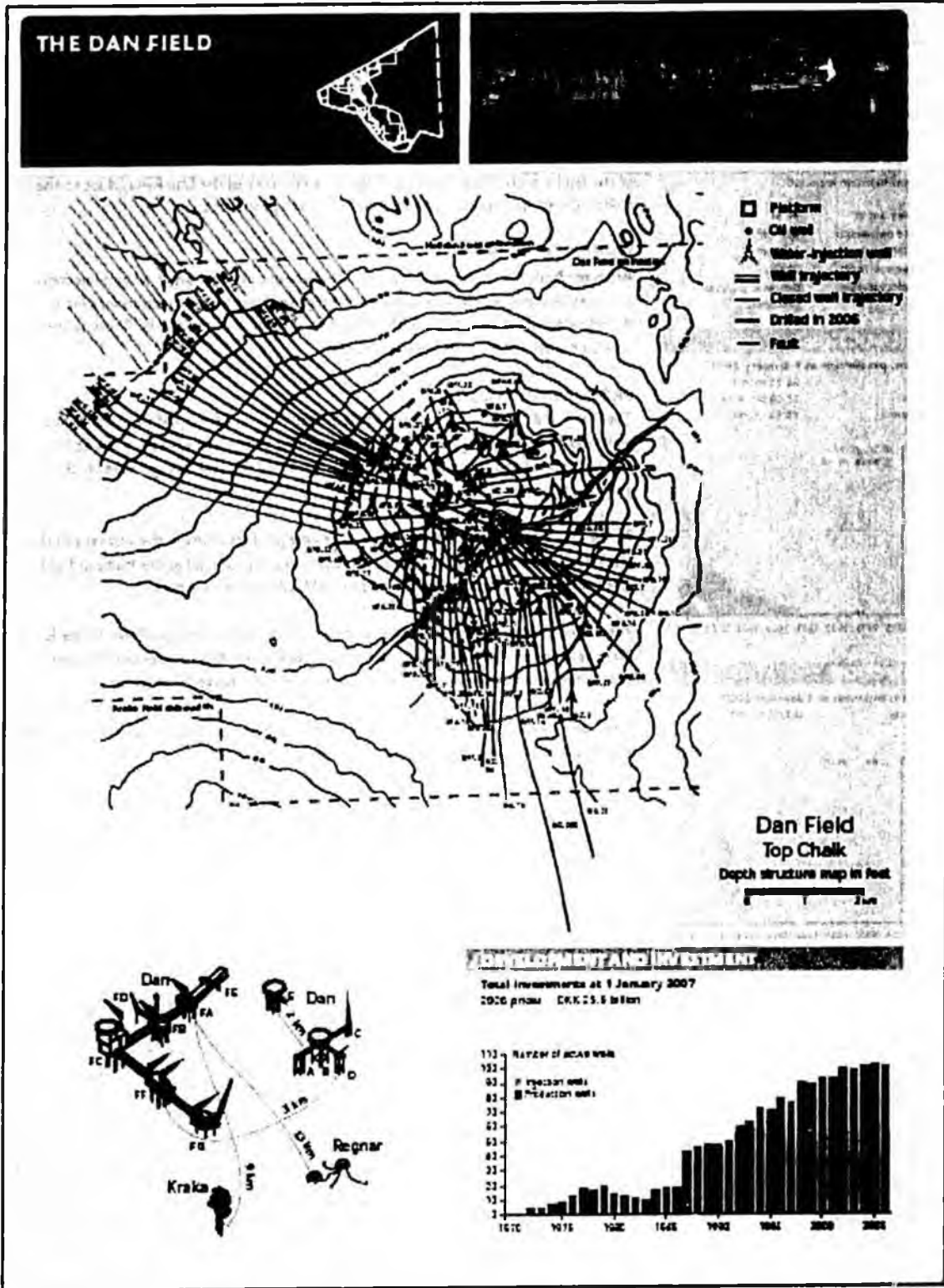
	2002	2003	2004	2005	2006*
Cocle	223	660	309	(18)	4
Dagmar	-	-	-	-	144
Den	437	943	750	750	684
Gorn	242	107	108	291	304
Halldan	2,411	1,779	1,124	683	1,199
Harald	0	4	22	53	1
Kraka	3	-	2	-	-
Nira	285	1,288	319	163	19
Raar	-	-	-	-	-
Rolf	-	37	4	-	1
Siri	111	466	425	73	160
Skjold	5	77	8	11	4
South Ama	849	764	742	310	461
Svend	223	-	-	-	-
Tyra	85	306	459	1,020	1,520
Tyra Southeast	569	82	96	46	-
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	-	-
Akna	-	0.6	0.5	-	-
Boje	-	-	-	0.8	-
Cocle	-	-	-	-	-
Dagmar	-	-	-	-	-
Den	0.9	0.6	-	-	-
Ely	0.3	1.6	-	-	-
Gorn	0.1	0.0	-	-	-
Halldan	2.0	0.9	0.1	-	-
Harald	0.0	0.1	-	-	-
Kraka	0.3	-	-	-	-
Lulita	-	-	-	-	-
Nira	0.1	-	-	-	-
Ragnar	-	-	-	-	-
Raar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.3	-	-	-	-
Skjold	-	-	-	-	-
South Ama	0.1	-	-	-	-
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





FIELD DATA as 1 January 2007

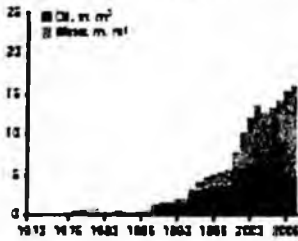
Project: Abby
Location: Block 2204/17
Licence: Sole Concession
Operator: Norsk Olie og Gas AS
Discovered: 1971
Year in stream: 1972

Producing wells: 36
Water-injection wells: 50

Water depth: 40 m
Field definition: 121 km²
Reservoir depth: 1,890 m
Reservoir rock: Chalk
Geological age: Danian and Upper Cretaceous

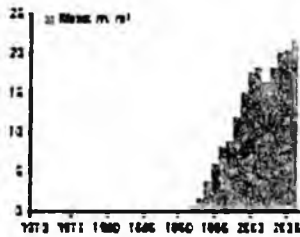
PRODUCTION

Cum. production as 1 January 2007
Oil: 84.35 m. m³
Gas: 21.08 bn. Nm³
Water: 69.19 m. m³



INJECTION

Cum. Injection as 1 January 2007
Water: 187.88 m. m³



REVENUE

Oil: 23.8 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

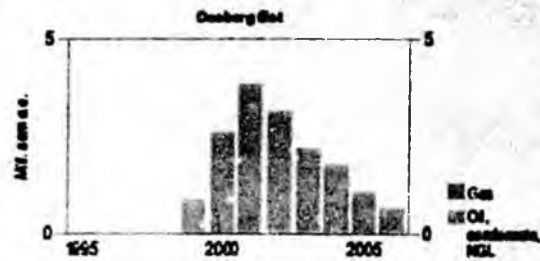
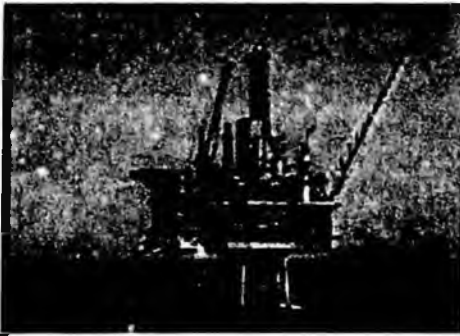
The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

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 license	Block 30/6 - production licence 021, awarded 1979												
Discovered	1961												
Development approved	11.10.1996 by the King in Council												
On stream	08.05.1999												
Operator	Norsk Hydro Produksjon AS												
Licensees	<table border="0"> <tr><td>Mobil Development Norway AS</td><td>4.50 %</td></tr> <tr><td>Norsk Hydro Produksjon AS</td><td>34.00 %</td></tr> <tr><td>Nordic ConocoPhillips AS</td><td>2.40 %</td></tr> <tr><td>Petoro AS</td><td>33.00 %</td></tr> <tr><td>Statol ASA</td><td>15.00 %</td></tr> <tr><td>Total E&P Norge AS</td><td>10.00 %</td></tr> </table>	Mobil Development Norway AS	4.50 %	Norsk Hydro Produksjon AS	34.00 %	Nordic ConocoPhillips AS	2.40 %	Petoro AS	33.00 %	Statol ASA	15.00 %	Total E&P Norge AS	10.00 %
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Nordic ConocoPhillips AS	2.40 %												
Petoro AS	33.00 %												
Statol ASA	15.00 %												
Total E&P Norge AS	10.00 %												
Responsible reserves	<table border="0"> <tr><td>Original</td><td>Reserves as of 31.12.2006</td></tr> <tr><td>27.8 million scm oil</td><td>11.7 million scm oil</td></tr> <tr><td>0.6 billion scm gas</td><td>0.2 billion scm gas</td></tr> </table>	Original	Reserves as of 31.12.2006	27.8 million scm oil	11.7 million scm oil	0.6 billion scm gas	0.2 billion scm gas						
Original	Reserves as of 31.12.2006												
27.8 million scm oil	11.7 million scm oil												
0.6 billion scm gas	0.2 billion scm gas												
Production	<table border="0"> <tr><td>Estimated production in 2007:</td><td></td></tr> <tr><td>Oil: 10 800 barrels/day</td><td>Gas: 0.65 billion scm</td></tr> </table>	Estimated production in 2007:		Oil: 10 800 barrels/day	Gas: 0.65 billion scm								
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Oil: 10 800 barrels/day	Gas: 0.65 billion scm												
Investment	<table border="0"> <tr><td>TOTAL investment is expected to be NOK 14.2 billion (2007 values)</td></tr> <tr><td>NOK 8.8 billion have been invested as of 31.12.2006 (2007 values)</td></tr> </table>	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)										
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NOK 8.8 billion have been invested as of 31.12.2006 (2007 values)													
Operating experience	16 years												
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 Sase 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 on stream in February 2008.

Appendix V:
Nova Scotia Detail
(from Deep Panuke Development Plan)

Year	P90		P50		P10		Mean	
	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /d)	(MMscfd)	(10 ⁶ sm ³ /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.

	CS Millions 2006
EnCana Project Management & Engineering	115
Subsea	135
Export Pipeline	200
Drilling and Completions	160
<i>Subtotal:</i>	610
<i>Contingency</i>	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.

October 25, 2007

TESTIMONY OF CRAIG HAYMES

ON PROPOSED SB 2001

TO THE ALASKA SENATE RESOURCES COMMITTEE ON OIL & GAS

OCTOBER 25, 2007

INTRODUCTION

Mr. Chairman, members of the committee:

Good morning. For the record, my name is Craig Haymes. I am the Production Manager for ExxonMobil in Alaska, a position I have held since January 2007. I have the pleasure of living in Anchorage with my family. Prior to January this year I was involved with Arctic oil and gas projects on the East coast of Canada for almost five years.

I want to thank the committee for the opportunity to express ExxonMobil's views today regarding the Administration's proposed tax increase.

Let me state upfront, ExxonMobil believes the current PPT tax rate and the increase proposed by the Administration will have a negative impact on resource investments in Alaska. ExxonMobil does not support the proposed tax increase by the Administration.

We believe that Alaska needs to focus on a long-term resource development policy. The policy should encourage increasing investment that is needed to maximize the development of Alaska's resources. Alaska is rich in undiscovered resource potential, yet oil production continues to decline from mature basins. Oil production today is one

third of the peak of over 2 million barrels per day in 1988. Alaska faces a significant challenge. We have a common goal to maximize economic resource development and need to work together; Government, industry, and the people of Alaska, to enhance the development of Alaska's rich resources and the future.

EXXONMOBIL IN ALASKA

ExxonMobil invests all over the world to meet the growing need for energy. Over the last 20 years we have invested close to \$280 billion dollars to search for new supplies of energy, build new production facilities, expand refinery capacity and deploy new, environmentally sound technologies.

ExxonMobil believes technology innovation is the key to meeting the world and Alaska's energy challenges. Technology is the lifeblood of our industry. ExxonMobil currently spends close to \$1 billion per year on research and technology. We have consistently applied our technology in Alaska to unlock and develop resources. We have significant arctic experience around the world.

Some examples of technology applications that we have contributed to Alaska are

- The installation of the ice resistant Granite Point platform in Cook Inlet, which is still producing oil.
- Significant research and engineering for the Prudhoe Bay completion designs for permafrost
- The installation of the first Concrete Island Drilling System (CIDS) to drill exploration wells in ice covered waters in the Alaska Beaufort Sea.

- The first full-field 3-D simulation model of Prudhoe Bay, leading to many enhanced oil recovery and development drilling programs that are still being pursued today.

The application of technology will continue to be a key to the future of Alaska's resource developments.

ExxonMobil has had a presence in Alaska for over 50 years and has been a key player in Alaska's oil industry development, spending and investing over \$20 billion dollars. We hold the largest working interest at Prudhoe Bay (36.4%) and our current working interest share of oil production in the state is approximately 150,000 barrels per day. We are also the largest owner of discovered Alaska gas resource.

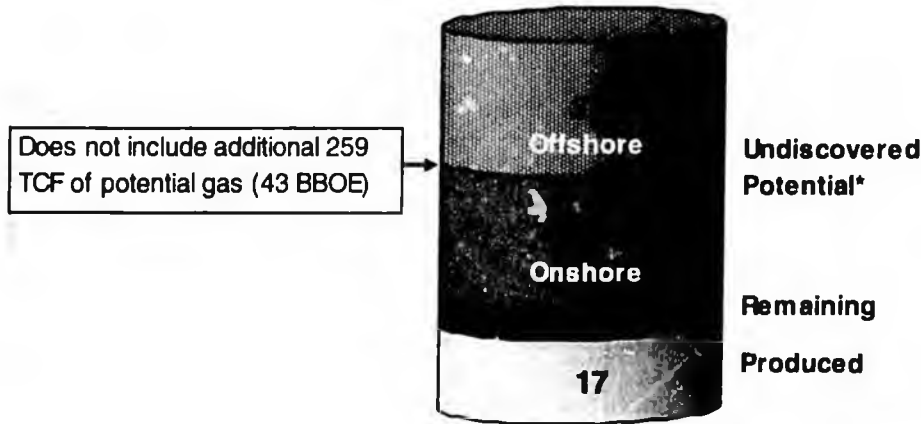
We are currently active with our co-owners at Prudhoe Bay, Kuparuk, Duck Island, Granite Point and Point Thomson. Over the last two years we have participated in the drilling of over 70% of the wells on the North Slope - over 130 wells were drilled at Prudhoe Bay alone - this drilling will add 50,000 B/D of oil production in 2007, an important contribution to help mitigate production decline.

We are proud of the role that our company has played in Alaska, which we believe has benefited both the State and the industry, and we look forward to working with Alaska for many years to come.

ALASKA RESOURCE POTENTIAL IS SIGNIFICANT

I would like to take a few moments to discuss Alaska's resource opportunities. Alaska has significant oil and gas resources. According to the US Geological Survey and the US Minerals Management Service, Alaska's undiscovered technically recoverable resources are 53 billion barrels of oil. This is in addition to the Department of Natural Resources estimate for known remaining oil resources of 6 billion barrels. To date Alaska has produced close to 17 billion barrels of oil - this is a world class result – but is less than one fourth of the potential total of 76 billion barrels. That is, Alaska still has the potential to produce another 59 billion barrels of oil. The gas resource potential almost doubles this undiscovered potential on an oil equivalent basis.

**Alaska Resource Assessment
76 Billion Barrels of Oil**



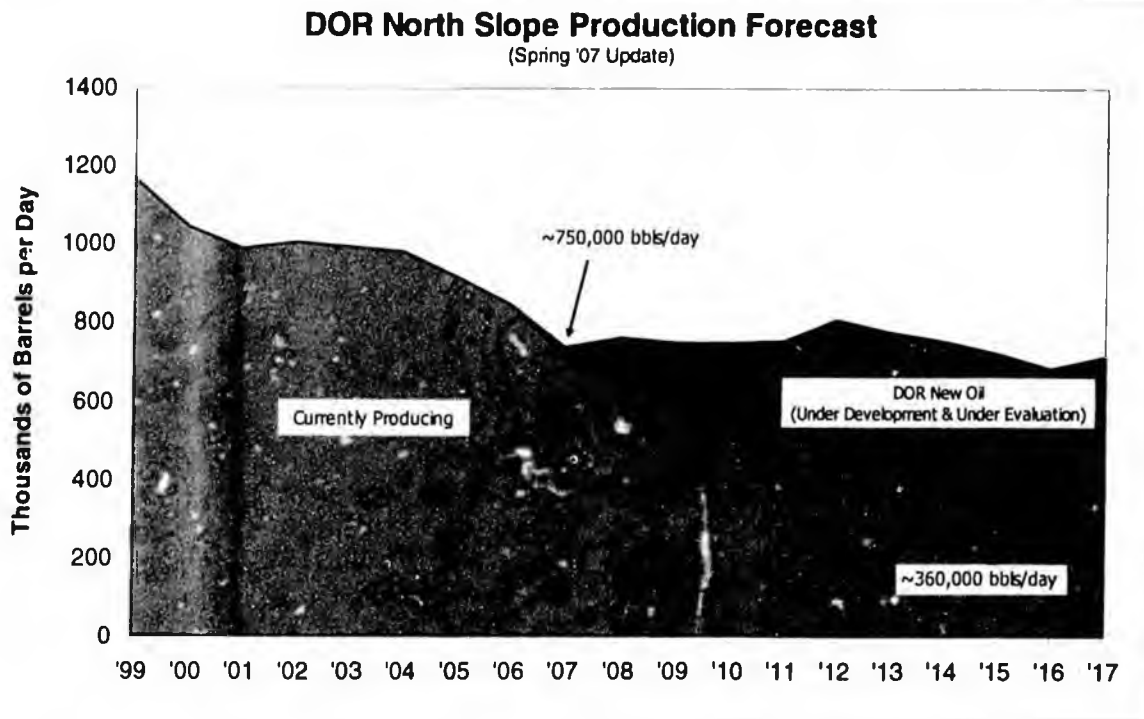
SOURCE: USGS, MMS, DNR

* mean undiscovered technically recoverable resource

Whilst Alaska's resource potential is high, the Oil and Gas Journal and Energy Information Administration report that its world ranking of proved reserves has declined from 14th in 1977 to a position closer to 30th today.

ALASKA'S FUTURE OIL PRODUCTION

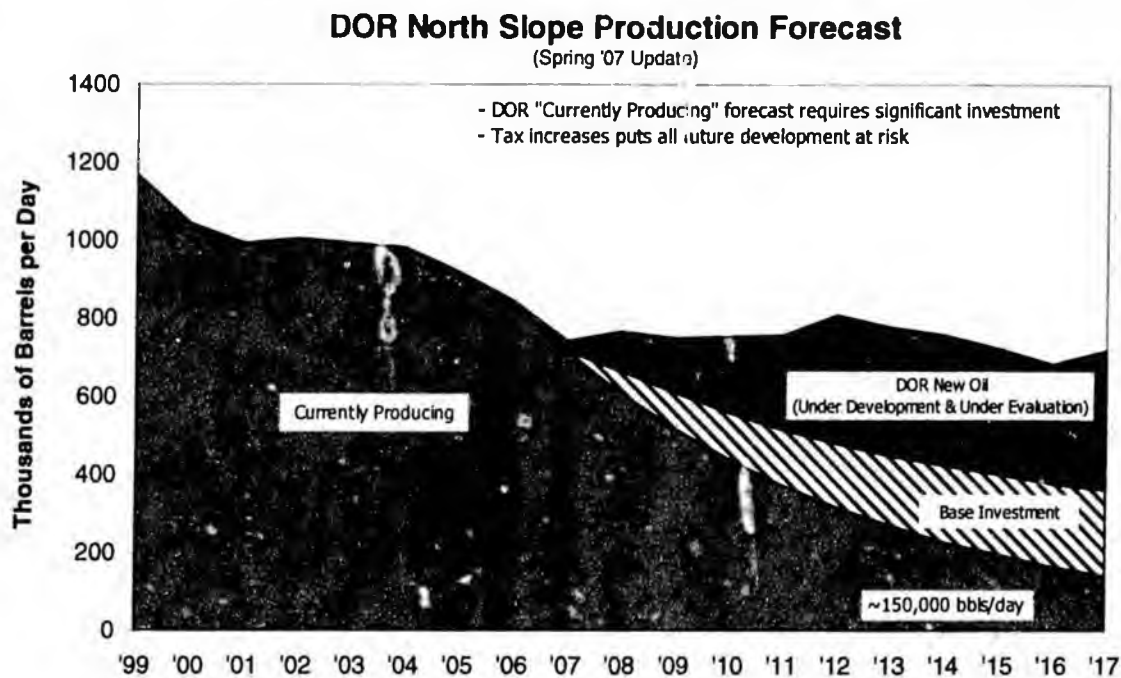
Today Alaska is producing approximately 750,000 barrels of oil per day from the North Slope, one third of its peak production. The Department of Revenue's production outlook, from their Spring Revenue Sources Book, shows that they estimate a 9% annual decline in Alaska's current base production. As the chart illustrates, at this decline rate, over the next ten years Alaska's current base production, shown in green, will drop to around 360,000 barrels per day. That is a production level of less than half of today's.



The Department of Revenue also forecasts that this base production decline will be partially mitigated with the development and production of oil in categories called "Under Development and Under Evaluation", shown in blue on the chart. These categories include future investments, such as development drilling, satellite developments, and enhanced oil recovery from existing fields. Based on this forecast, over 50% of the

projected oil production in 10 years will come from new investments. Let me say that again, 50% of future oil production in 10 years is not even developed or producing today. Considering that most new projects take at least 5-7 years to bring to production on the North Slope, investment decisions for these activities, particularly in the near term, will be critical to underpin the future of Alaska's oil production.

As I mentioned earlier, the Department of Revenue forecast is based on a 9% annual decline in Alaska's current base production. However, this decline assumes that production enhancement investments at the core Prudhoe Bay, Kuparuk and Alpine areas continue. The Department of Revenue forecast, as shown, does not highlight that this activity requires investment decisions that are no different from the "Under Development and Under Evaluation" categories. As such, a more accurate representation of the future oil production and investment levels required to achieve the Department of Revenue forecast is illustrated in the following chart.



As this chart shows, Alaska's oil production from the North Slope could be as low as 150,000 barrels per day within 10 years, (assuming 15% decline, which is typical for large oil fields such as Prudhoe Bay), without ongoing and increasing investment. Based on this forecast, within 10 years, 75% of production will come from new investments.

Conservatively, we estimate that at least \$30-40 billion of investment is required within the next 10 years to achieve the Department of Revenue forecast. This does not include the billions of dollars of additional operating expenditures that would be required to support the developments once they are producing. This is a significant level of future investment and spending.

The high tax rate in PPT and the proposed tax increase put this investment at significant risk. Alaska needs to encourage the increasing investments required, not only in exploration activities, but also in the ongoing development of existing and new fields.

ALASKA IS A HIGH COST REGION

Complicating the significant future investments required to mitigate Alaska's production decline is its high costs. Alaska has unique challenges resulting in a high cost environment for exploration and development and very mature producing fields with growing unit costs. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- A sensitive environment, requiring significant and due diligence measures to protect it
- Remote location of the resource and distance to market
- Current restrictions for future exploration opportunities

All combine to create a unique and high cost environment for Alaska.

ALASKA'S SO-CALLED LEGACY FIELDS

The two largest oil fields in Alaska - Prudhoe Bay and Kuparuk, have been producing since 1977 and 1981, respectively. Today these two fields account for over 70% of the State's North Slope oil production. Assuming that exploration and investment activity continues in these fields, they could remain at this level of production contribution for the next decade.

These so called legacy fields require continuous investment to keep the oil flowing and the facilities operating at capacity. This is the same for any oil field in the world. During the production phase there are many changes in operating parameters, such as reservoir pressure changes, oil, gas and water production changes, changes in operating conditions, and ongoing technical challenges. In order to keep the oil flowing these changes require additional investments, such as the addition of water and gas injection and gas compression facilities, which are historical significant investments at Prudhoe Bay.

Currently, the owners spend over \$2 billion dollars to optimize and enhance production from Prudhoe Bay and Kuparuk. These spending levels are in addition to the capital investments pursuing new wells, projects, and enhanced oil recovery opportunities. These operating expenditures are essential to mitigate production decline at these significant fields, which are critical to the future of Alaska's North Slope oil production.

Many of today's exploration and development activities are occurring in and around Prudhoe Bay and Kuparuk.

As an example, since the year 2000 there have been multiple Prudhoe Bay satellite fields developed - Aurora, Borealis, Midnight Sun, Polaris, and Orion - which are currently contributing over 40,000 B/D of oil production. These developments would not have been possible without the infrastructure and facility sharing of Prudhoe Bay, which reduced the development and operating costs of these satellites. As satellite fields are developed it reduces exploration and development costs for future new projects, as the infrastructure on the North Slope expands.

If the major Prudhoe Bay and Kuparuk developments did not exist these satellite fields would not have been economic to develop.

As another example, for the past seven years over 900 new wells have been drilled in Prudhoe Bay and Kuparuk. The drilling of these new wells has slowed the overall production decline from 12-15% to an estimated 6-9%. Almost 40% of Prudhoe Bay's production today is from these new wells.

For the past two years, development drilling at Prudhoe Bay has achieved the equivalent of the important Oooguruk development. This example highlights the importance of exploring for and developing new oil in and around the Prudhoe Bay and Kuparuk fields – all are important to the economic benefit and future of Alaska.

Let me re-emphasize that Prudhoe Bay and Kuparuk have the potential to continue to be critical contributors to Alaska's oil production. They have the potential to remain key hubs and enablers for exploration and development of heavy or viscous oil, light oil and gas. Encouraging increasing investment at these key fields is as important as encouraging investment in exploration and development of new fields. Without these two hubs, Alaska will be severely challenged to realize the full potential of its resources.

Progressing a tax policy that singles out and penalizes these fields will discourage investment not only at these fields but will also impact future investment attractiveness to explore and develop other Alaska oil and gas resources.

PROPOSED TAX INCREASE MORE COMPLICATED

In analyzing the Administration's tax proposal, we found that virtually all of the provisions are simply tax rate increases or further increases in complexity.

As an example, under the Administration's proposed tax increase the two so-called Legacy Fields, Prudhoe Bay and Kuparuk, would have a separate 10% gross minimum tax and be segregated from each other and all other North Slope fields. This gross tax would be in addition to the base royalty payments. With this minimum gross tax the State would be insulated from price and cost risks, whilst retaining the upside potential from the progressivity element. The Administration is simply proposing to increase its take while shifting the development risks to the producers. Essentially, at low price, producers are penalized.

October 25, 2007

Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential and a sharing of risk should prices fall. Under the Administration's proposed tax increase, investors will need to assume a higher economic risk when making funding decisions for future investments and spending.

The Administration has also proposed that all revenues and expenses for the Legacy Fields will have to be accounted for separately, with separate taxes paid for each unit and their satellites. This would include Alaska's heavy or viscous oil reserves produced from those Legacy Fields - a resource that already has significant economic and technical hurdles to overcome. No other fields, units or regions within the state would be subjected to these administrative burdens.

The ring-fencing of the Prudhoe Bay and Kuparuk Units makes the tax proposal more complex than the existing PPT.

EXXONMOBIL POSITION ON THE ENACTED PPT

I believe it is important that I clarify ExxonMobil's position on the current PPT.

ExxonMobil did not support the PPT that was enacted last year. As we testified last year, we supported the concept of a net based tax but stated that the proposed 20% tax rate, in the original PPT bill, would not encourage the full development of Alaska's resources. We agreed with the 20% tax rate in order to support the progression of a gas pipeline project.

The PPT that was ultimately enacted increased the already high 20% base tax rate to 22.5% with progressivity - more than doubling industry's taxation. Alaska's current PPT tax rate is too high. When combined with the gross royalties and the high development and operating costs, it makes Alaska one of the most expensive regions to invest.

There has been a lot of discussion recently on PPT revenues and forecasts, which has been used in part to support the Administration's proposal to increase taxes. PPT has only been in existence for slightly more than one year. The Department of Revenue has not completed its PPT regulations or started any PPT audit. ExxonMobil, like a number of the other producers, met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts. We are also willing to work with DOR auditors to improve their understanding of joint interest billings.

FISCAL PREDICTABILITY IS IMPORTANT

I would now like to address another important element of the business environment - fiscal predictability. ExxonMobil, and I believe the industry, values a predictable fiscal environment in which to make long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view predictability of the Alaskan fiscal environment, which in turn directly impacts how we evaluate on a risk basis future investment decisions. Let me reemphasize this point. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the amount of time required to recoup that investment, fiscal terms that are predictable are key to any investment decision.

The Administration's proposed tax increase would represent the third significant change to Alaska's fiscal terms in the past three years. Changing the fiscal environment for capital intensive projects, that take many years to generate a return, can only reduce the attractiveness of future investments. Each time taxes are raised, the attractiveness of any prospective well or project diminishes and the likelihood of it not being funded increases. For every well or project not progressed, additional production and State revenues are lost. As mentioned earlier, to mitigate oil production decline Alaska needs to increase investment. The Administration's proposed tax increase will reduce investment.

ExxonMobil expects to be involved in Alaska for many years to come. The policies established today and in the future will impact the attractiveness of future potential projects and the future of Alaska.

ALASKA NEEDS A LONG-TERM RESOURCE DEVELOPMENT POLICY

As I mentioned earlier, Alaska has significant resource potential, but with many unique cost challenges. It will take significant resources, technology, investment and teamwork from everyone to realize the full potential. Alaska and industry collaboratively need to create a resource development policy that encourages investment for long-term production and growth. This is a complex issue and needs significant time and effort from all parties. It is beneficial to look at what others have done.

The Canadian province of Alberta has enormous unconventional crude oil resources. Alberta's oil sands represent the potential of over 170 billion barrels of crude, and, like Alaska's resources, are located in higher cost, remote arctic regions that require significant investments to develop.

Alberta adopted a resource development policy approach, designed to increase industry investment and production. Their approach has proven successful due to a number of key factors:

- Collaborative pursuit of resource development objectives
- Development of technologies jointly with industry to reduce costs, increase oil recovery, and upgrade viscous oil to marketable products
- Creation of a level playing field for all projects
- Sharing risks with the investors by maintaining a lower gross revenue based tax, that is, lowering royalties significantly
- Providing long term fiscal predictability

Alberta's success suggests that Alaska should seriously consider what other regions are doing to encourage investment.

A long-term sustainable resource development policy is required to enable Alaska to maximize its oil and gas resource. There are many factors that need to be considered. It is a complex issue. I hope that key points addressed in my testimony are considered:

- Alaska has significant resource potential, but it is in a high cost environment
- Oil production is already one third of its peak, yet we have only produced one fourth of the oil resource potential
- In 10 years, 75% of Alaska's future oil production needs over \$30-40 billion of new investments - investments that are needed sooner than 10 years.
- Prudhoe Bay and Kuparuk are the "hub" of the North Slope, they
 - Represent 70% of North Slope oil production for the next 10+ years
 - Can be the backbone for future exploration and economic developments, whether it is existing production, future light oil, heavy oil, or gas
 - Need increasing investments to achieve their potential
- Development drilling at Prudhoe Bay and Kuparuk over the last 2 years has added 50,000 B/D of new oil production in 2007

We propose a collaborative approach to develop a sustainable long term resource policy that will encourage the needed increasing investments and build the future of Alaska for many generations to come. ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of its oil and gas resources.

October 25, 2007

To encourage full development of Alaska's resources, the PPT tax rate needs to be lowered, and should not include a gross revenue based component. Increasing investment fuels the economy.

Thank you again Mister Chairman for the opportunity to testify today.