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
1360 Post Oak Boulevard, Suite 2500
Houston, Texas 77056

Telephone: (713) 850-9955
Facsimile: (713) 850-9966
Email: gcah@gaffney-cline.com

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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

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

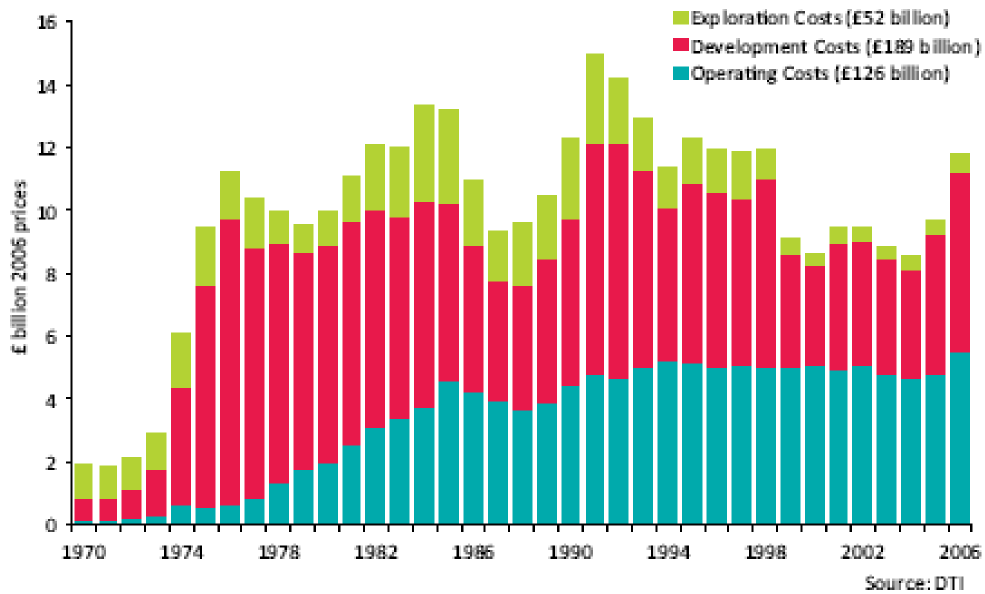
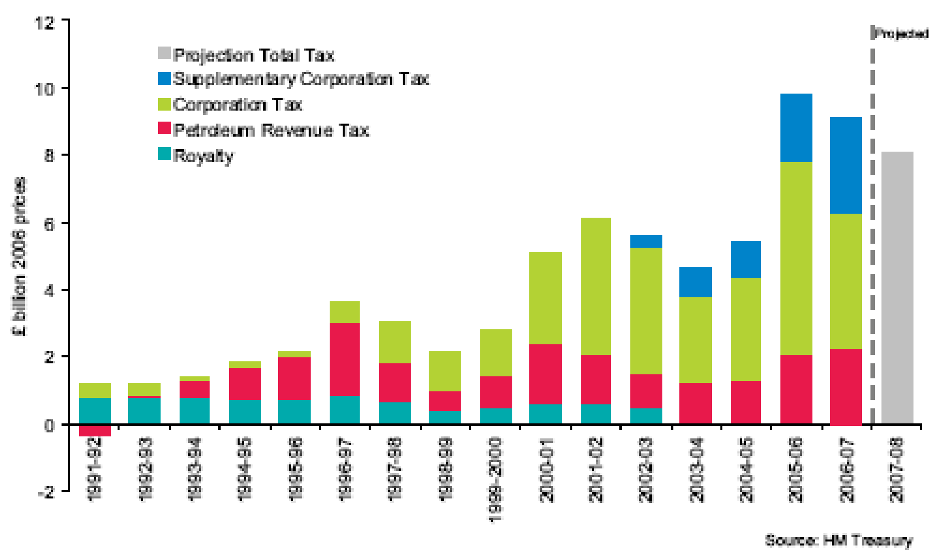


Figure 6: UKCS Taxes 1991-2008



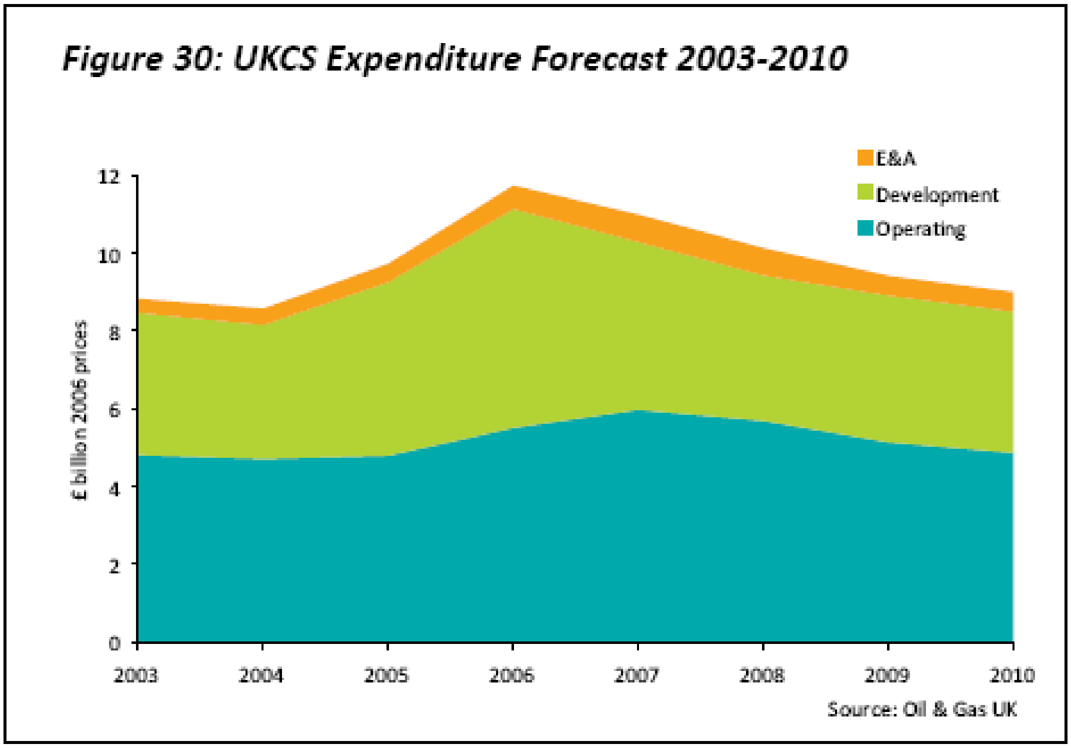


Figure 30: UKCS Expenditure Forecast 2003-2010
E&A
Development
Operating
£ billion 2006 prices
0
2
4
6
8
10
12
2003
2004
2005
2006
2007
2008
2009
2010
Source: Oil & Gas UK

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 decomm-issioning 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	**6**	6	*n/a*	0	**6**	-2	20	*n/a*	53	**73**	n/a	n/a	9.9
1971	0	0	80	8	**88**	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*	584	**737**	n/a	n/a	14.4
1975	43	15	190	29	**277**	46	*n/a*	0	**46**	231	242	*n/a*	1,374	**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	**2,563**	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	261	*n/a*	2,170	**2,431**	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	**2,306**	n/a	3.8	30.7
1980	8,719	132	647	82	**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	**1,063**	12,235	550	*n/a*	2,847	**3,397**	n/a	6.5	40.8
1982	14,129	312	956	160	**15,557**	1,309	*n/a*	73	**1,382**	14,174	875	*n/a*	3,059	**3,934**	142.0	7.4	43.9
1983	16,496	528	1,117	188	**18,328**	1,495	*n/a*	67	**1,562**	16,767	993	*n/a*	2,853	**3,846**	148.3	8.4	46.3
1984	19,927	659	1,290	256	**22,133**	1,733	*n/a*	62	**1,796**	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*	2,794	**4,239**	158.3	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	**3,458**	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	859	**10,238**	2,060	*n/a*	58	**2,118**	8,120	1,129	*n/a*	2,126	**3,255**	63.4	13.1	59.2
1989	7,214	272	2,187	547	**10,220**	2,330	*n/a*	57	**2,386**	7,833	1,182	*n/a*	2,635	**3,817**	81.1	14.2	63.6
1990	8,432	277	2,377	405	**11,491**	2,892	*n/a*	46	**2,938**	8,552	1,637	*n/a*	3,478	**5,116**	94.6	14.3	68.5
1991	7,578	385	2,988	476	**11,426**	3,296	*n/a*	58	**3,354**	8,073	1,955	*n/a*	5,101	**7,057**	86.0	15.9	73.0
1992	7,430	380	3,016	626	**11,453**	3,312	*n/a*	53	**3,365**	8,088	1,508	*n/a*	5,428	**6,936**	81.9	15.8	76.0
1993	8,110	523	3,568	699	**12,899**	3,661	*n/a*	47	**3,708**	9,191	1,213	*n/a*	4,661	**5,874**	85.8	15.0	78.0
1994	8,964	528	3,836	974	**14,302**	3,860	*n/a*	40	**3,900**	10,401	939	*160*	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	1,085	*204*	4,355	**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	1,097	*190*	4,364	**5,461**	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	1,194	*151*	4,263	**5,457**	87.4	16.7	86.6
1998	7,487	551	5,313	1,453	**14,806**	4,190	*n/a*	111	**4,301**	10,503	762	*125*	4,996	**5,758**	59.8	16.2	88.9
1999	10,257	727	5,031	1,436	**17,450**	4,249	*n/a*	282	**4,531**	12,920	457	*66*	3,063	**3,520**	80.0	13.7	90.9
2000	16,275	1,117	6,606	1,488	**25,486**	4,360	*n/a*	106	**4,466**	21,020	348	*40*	2,750	**3,098**	138.1	15.8	92.1
2001	13,646	963	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**	4,596	*n/a*	48	**4,643**	19,475	389	*46*	3,598	**3,988**	123.8	16.4	97.0
2003	13,365	1,105	7,554	1,538	**23,562**	4,496	*n/a*	8	**4,504**	19,058	334	*42*	3,412	**3,746**	130.0	17.4	100.0
2004	13,477	1,266	7,443	1,178	**23,364**	4,664	*146*	87	**4,751**	18,613	396	*67*	3,302	**3,698**	154.0	21.0	102.6
2005	16,656	1,684	8,902	1,451	**28,693**	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:

Type of development:

Discovery date:

Depth:

CONVERSION FACTOR	
Oil	
NGL	
Gas	

Please indicate barrel:tonne and scf:therm conversion factors

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:

Premium/discount to Brent Crude:

Please indicate using plus or minus $ per barrel or p/therm

Notes:

EXPORT ROUTE	
Oil	
NGL	
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

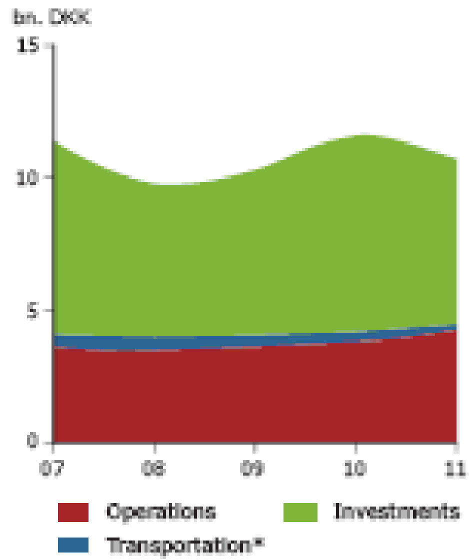
	2002	2003	2004	2005	2006*
Cecilie	223	660	309	(18)	4
Dagmar	-	-	-	-	148
Dan	437	943	750	750	684
Gorm	242	107	108	291	304
Halfdan	2,412	1,779	1,124	683	1,293
Harald	0	4	22	53	1
Kraka	3	-	2	-	-
Nini	285	1,288	319	163	19
Roar	-	-	-	-	-
Rolf	-	37	4	-	1
Siri	111	406	425	73	140
Skjold	5	77	8	11	4
South Arne	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

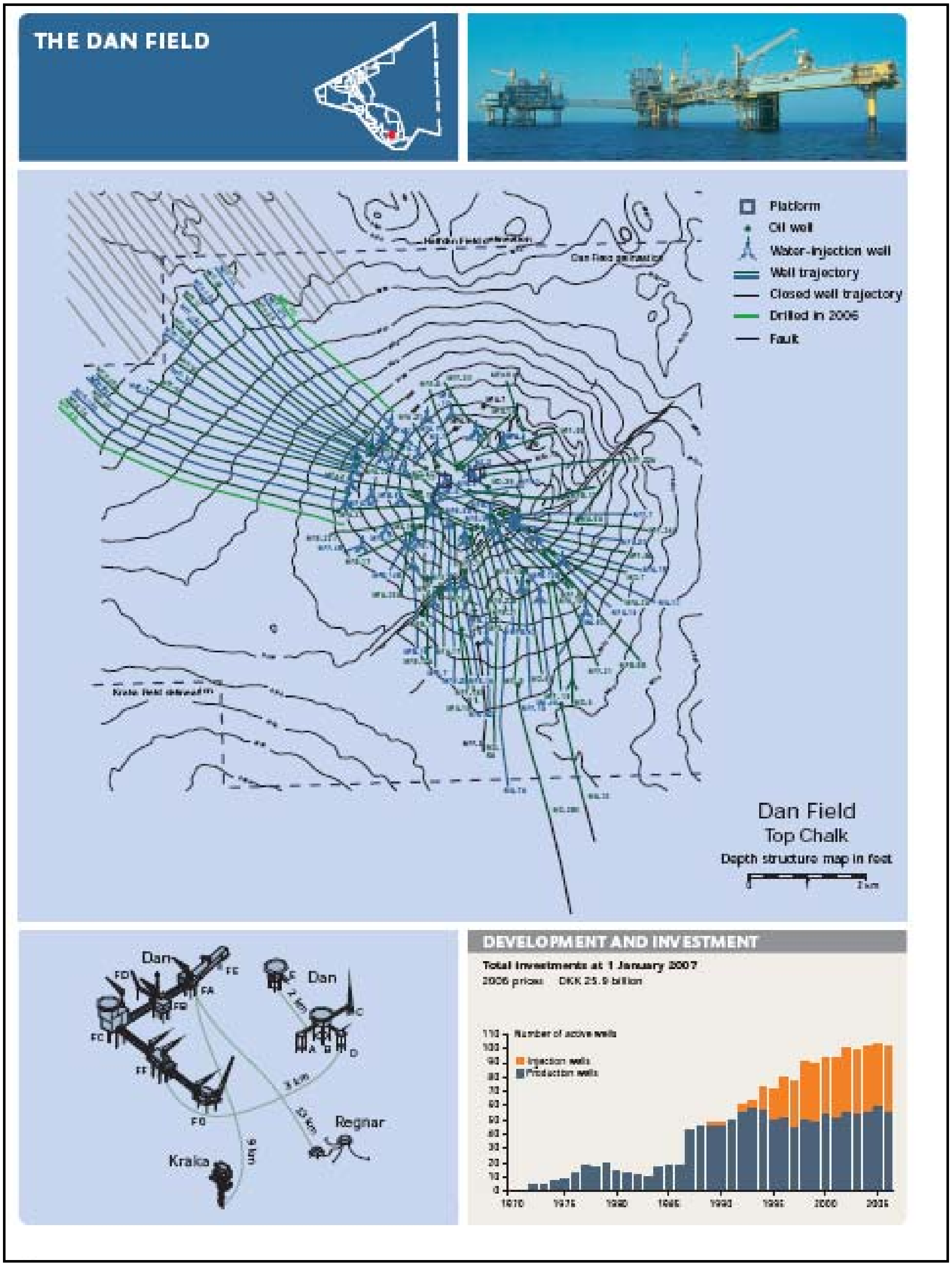
Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

	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

Fig. 7.5 Investments in fields, operating and oil transportation costs, 2006 prices



* *Excl. pipeline tariff/compensatory fee*


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
Total investments at 1 January 2007
2006 prices DKK 25.9 billion
Number of active wells
Injection wells
Production wells

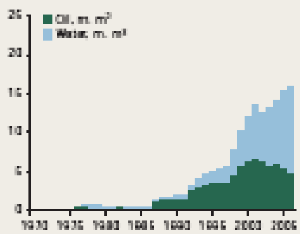
FIELD DATA at 1 January 2007

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	56
Water-injection wells:	50
Water depth:	40 m
Field delineation:	121 km^2
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2007

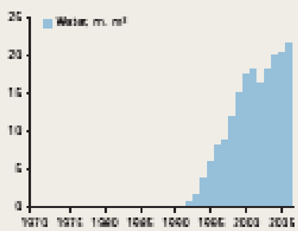
Oil:	86.35 m. m^3
Gas:	21.08 bn. Nm^3
Water:	69.19 m. m^3



INJECTION

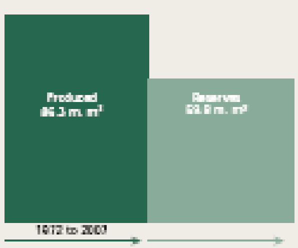
Cum. injection at 1 January 2007

Water:	197.88 m. m^3



RESERVES

Oil:	59.8 m. m^3
Gas:	6.3 bn. Nm^3



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.

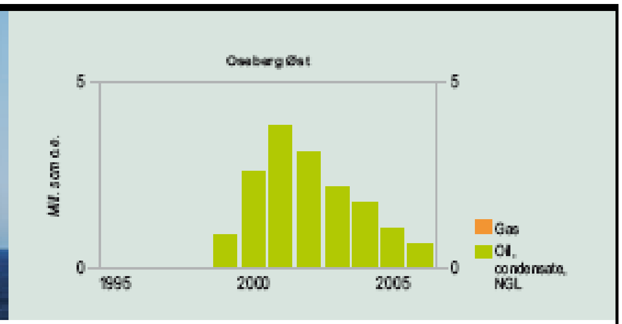
At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

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	15,30 %
	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 8,3 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.