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

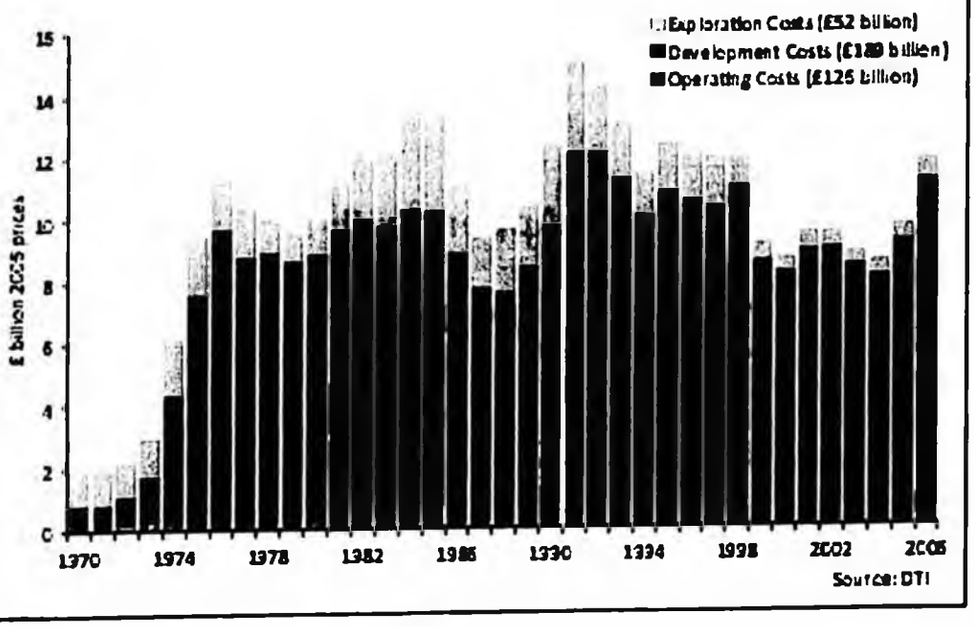


Figure 6: UKCS Taxes 1991-2008

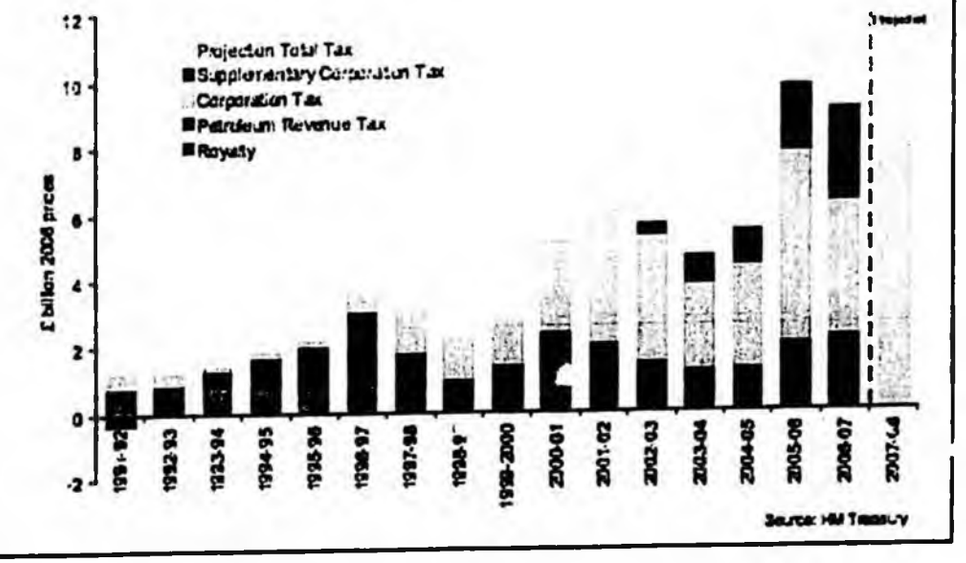
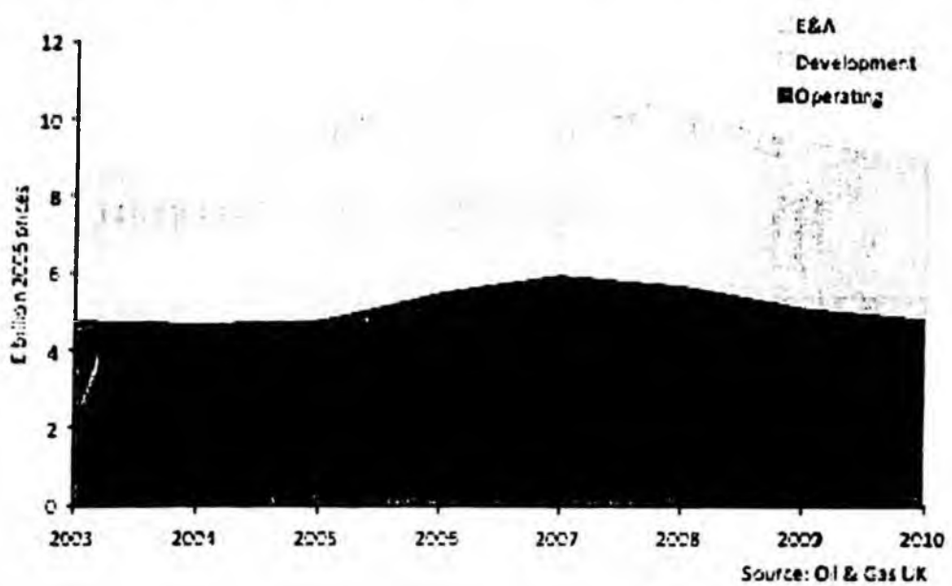


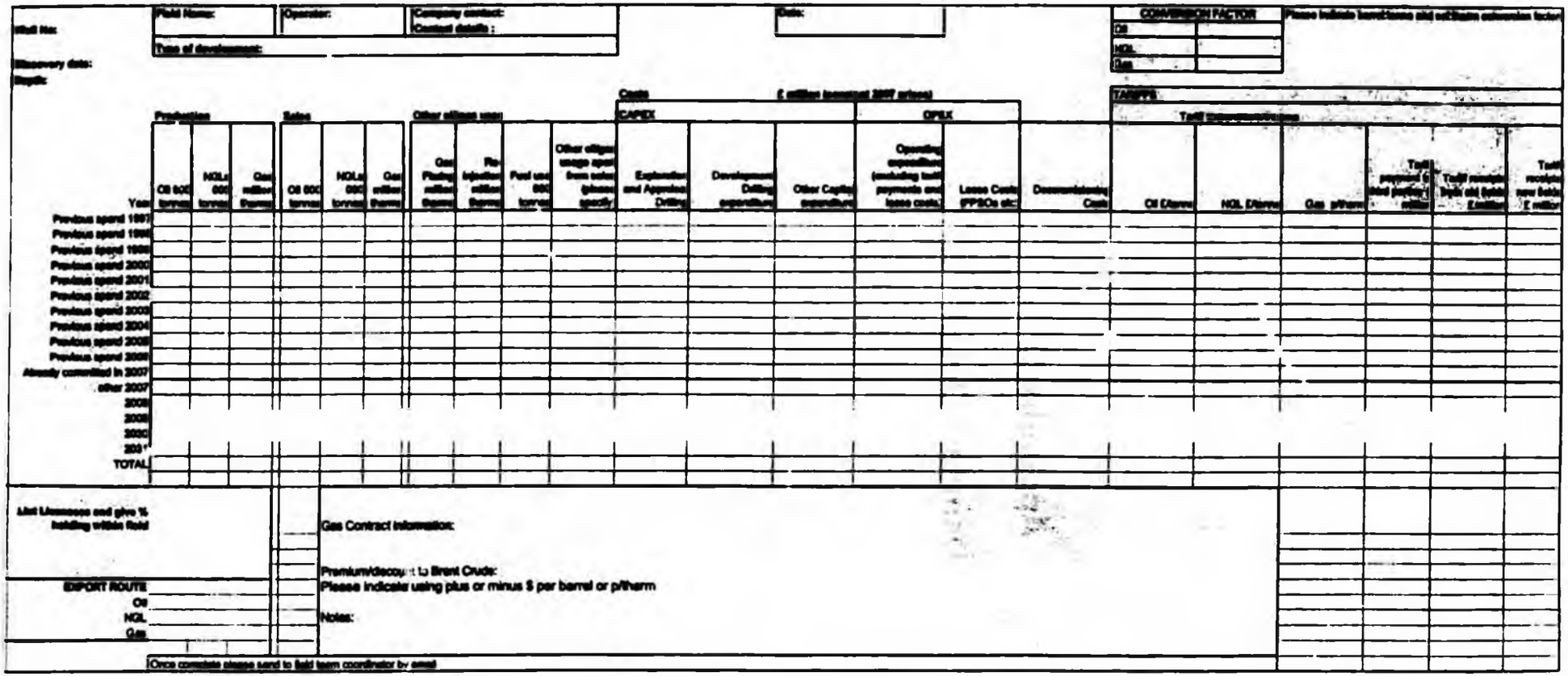
Figure 30: UKCS Expenditure Forecast 2003-2010



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

	Income					Expenses					Capital Expenditure				Prices		
	Oil Sales	NGL Sales	Gas Sales	Other Income[1]	Total Income	Operating Costs	of which decommissioning costs	Other expenses[2]	Total Expenses	Gross Operating Surplus[3]	E&A[4]	of which seismic	Investment other than E&A	Total	Average Oil Price (£/tonne)	Average Gas Price (p/therm)	GDP Deflator (2003=100)
1970	0	0	2	4	6	6	n/a	0	6	-3	23	n/a	53	76	n/a	n/a	9.9
1971	0	0	53	8	61	11	n/a	0	11	50	67	n/a	72	139	n/a	n/a	10.8
1972	0	1	114	9	124	15	n/a	0	15	110	43	n/a	112	155	n/a	n/a	11.7
1973	0	2	132	11	145	16	n/a	0	16	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	193	26	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	2,371	n/a	1.8	21.1
1977	2,197	29	317	23	2,566	237	n/a	0	237	2,329	375	n/a	2,107	2,482	n/a	2.1	24.0
1978	2,771	35	432	12	3,250	346	n/a	0	346	2,904	281	n/a	2,120	2,401	n/a	3.1	25.6
1979	5,641	53	538	44	6,276	532	n/a	18	550	5,726	241	n/a	2,064	2,305	n/a	3.8	30.7
1980	8,719	132	647	82	9,580	692	n/a	34	726	8,854	378	n/a	2,388	2,767	n/a	4.2	36.7
1981	12,205	135	843	114	13,297	1,317	n/a	45	1,362	12,336	583	n/a	3,047	3,597	n/a	6.5	40.6
1982	14,129	312	968	163	15,567	1,339	n/a	73	1,412	14,174	675	n/a	3,089	3,764	142.8	7.4	43.9
1983	16,486	628	1,117	189	18,420	1,596	n/a	67	1,663	16,757	993	n/a	2,053	3,046	148.3	8.4	46.3
1984	19,827	683	1,393	256	22,160	1,733	n/a	52	1,785	20,375	1,355	n/a	3,189	4,544	164.9	13.3	48.4
1985	19,254	692	1,739	264	21,950	2,248	n/a	76	2,324	19,625	1,446	n/a	2,754	4,200	158.3	11.8	51.1
1986	8,959	386	1,927	405	11,677	2,144	n/a	57	2,201	9,476	1,038	n/a	2,419	3,457	73.8	12.6	52.9
1987	9,513	388	1,993	533	12,424	2,107	n/a	95	2,202	10,222	669	n/a	2,044	2,713	81.7	12.6	55.7
1988	7,284	240	2,046	698	10,268	2,063	n/a	56	2,119	8,149	1,129	n/a	2,126	3,255	63.4	13.1	59.2
1989	7,214	272	2,187	547	10,220	2,333	n/a	57	2,390	7,830	1,182	n/a	2,635	3,817	81.1	14.2	63.6
1990	8,432	277	2,277	435	11,421	2,862	n/a	46	2,908	8,513	1,637	n/a	3,478	5,115	94.6	14.3	68.6
1991	7,578	386	2,988	478	11,430	2,998	n/a	59	3,057	8,373	1,966	n/a	5,101	7,067	86.8	15.9	73.0
1992	7,438	383	3,016	626	11,463	3,313	n/a	53	3,366	8,097	1,606	n/a	5,422	7,028	81.3	15.8	76.0
1993	8,110	621	3,553	605	12,889	3,681	n/a	47	3,728	9,161	1,213	n/a	4,661	5,874	96.6	16.0	78.0
1994	8,964	628	3,836	974	14,402	3,863	n/a	40	3,903	10,499	939	159	3,071	4,010	77.3	16.3	79.2
1995	9,881	614	4,141	1,156	15,792	3,913	n/a	37	3,950	11,842	1,056	234	4,385	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	1,037	139	4,364	5,401	97.3	16.6	84.2
1997	10,301	733	5,254	1,273	17,561	4,150	n/a	34	4,184	13,377	1,194	151	4,273	5,467	67.4	16.7	86.6
1998	7,487	551	5,313	1,453	14,804	4,190	n/a	111	4,301	10,503	762	129	4,006	4,768	59.8	16.2	88.0
1999	10,267	727	5,031	1,435	17,460	4,338	n/a	202	4,540	12,920	457	66	3,063	3,520	83.0	13.7	90.9
2000	16,275	1,117	6,636	1,458	25,486	4,363	n/a	106	4,469	21,017	340	42	2,760	3,100	130.1	15.8	92.1
2001	13,646	982	8,142	1,439	24,195	4,347	n/a	49	4,396	19,799	423	34	3,576	3,999	125.7	18.0	94.1
2002	13,629	884	8,199	1,397	24,109	4,586	n/a	48	4,634	19,475	389	45	3,558	3,947	123.8	16.4	97.0
2003	13,366	1,135	7,584	1,538	23,623	4,436	n/a	8	4,444	19,179	314	42	3,432	3,746	113.3	17.4	100.0
2004	13,477	1,258	7,443	1,178	23,374	4,674	140	87	4,761	18,613	356	57	3,302	3,658	154.3	21.3	102.6
2005	16,636	1,684	8,922	1,451	28,693	5,113	412	128	5,241	23,452	463	34	4,371	4,834	216.8	27.4	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.



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	680	208	(18)	4
Dagmar	-	-	-	-	148
Dan	437	943	750	750	684
Gorm	242	307	208	291	304
Halfdan	2,611	1,779	1,324	680	1,200
Harald	0	4	22	53	3
Krabs	3	-	2	-	-
Nini	285	1,285	319	163	28
Rolf	-	27	4	-	1
Sif	111	406	415	73	160
Skjold	5	77	8	11	4
South Arne	849	764	742	310	451
Svend	223	-	-	-	-
Tyra	85	305	459	1,010	1,520
Tyra Southeast	569	82	96	45	-
Valdemar	(1)	290	22	553	992
NOGAT pipeline	-	766	664	22	-
Not allocated	31	(31)	2	5	87
Total	5,475	7,386	6,185	3,961	6,658

*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	0.2	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.1	-	-	-	-
Regnar	-	-	-	-	-
Rear	-	-	-	-	-
Rolf	-	-	-	-	-
Sif	0.2	-	-	-	-
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	5.3	1.5	0.8	1.3
Planned	-	-	-	-	0.8
Possible	-	0.7	4.7	6.6	4.0
Expected	7.3	6.0	6.2	7.4	6.2

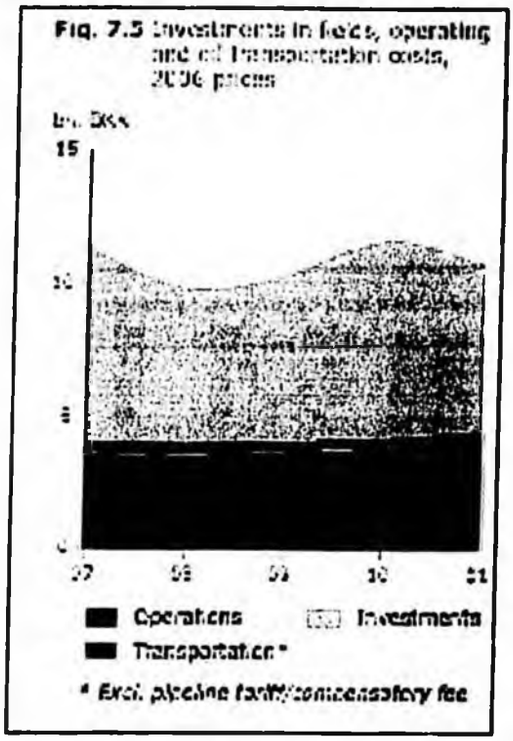
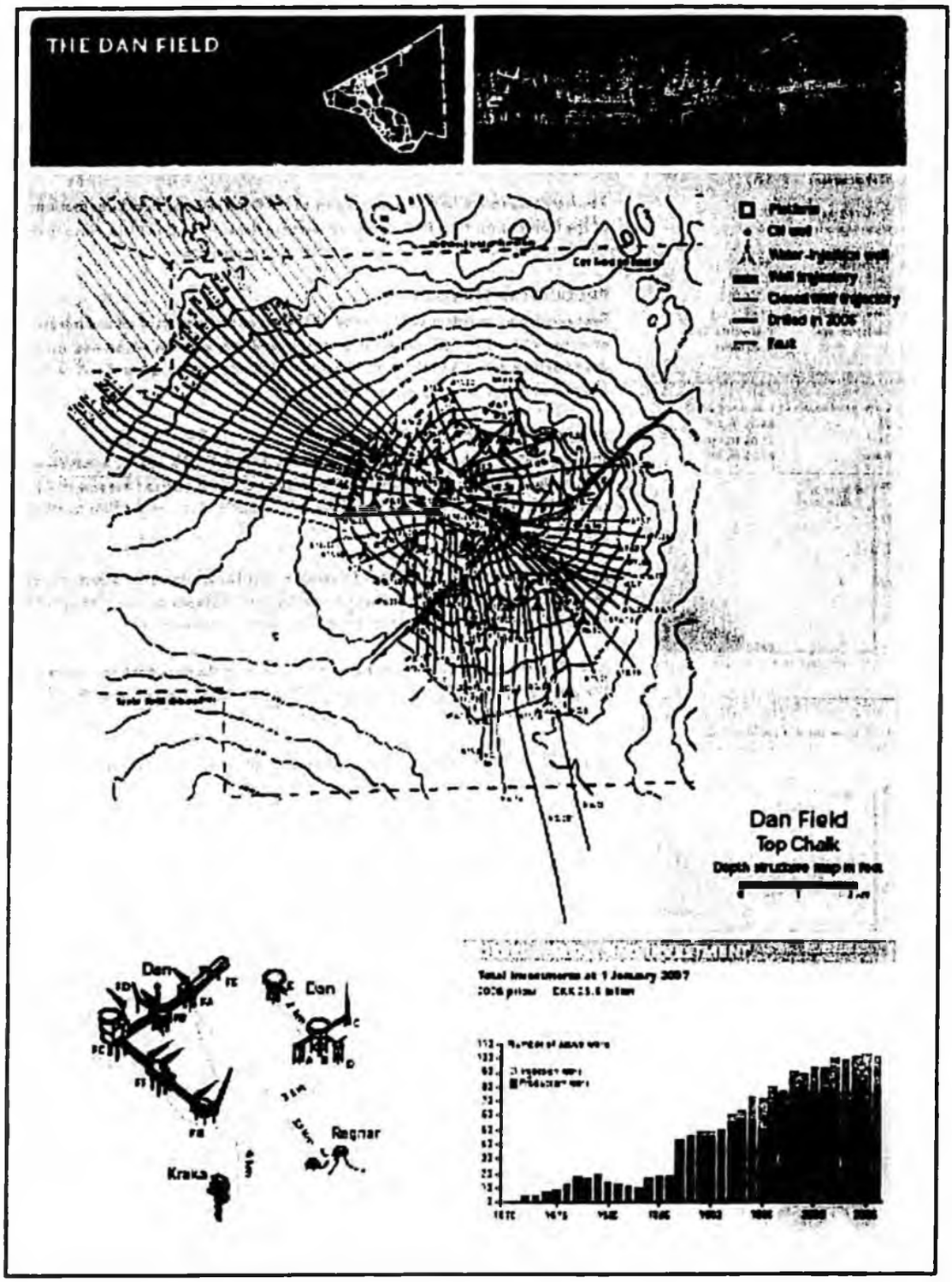


Fig. 7.5 Investments in fields, operating and oil transportation costs, 2006 prices


THE DAN FIELD
Dan Field
Top Chalk
Dan
Ragnar
Kraka

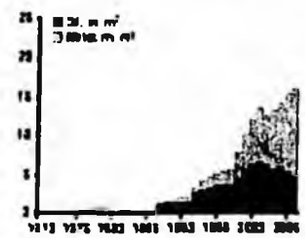
FIELD DATA

Year on stream: 1972

Water depth: 40 m
Reservoir depth: 1,980 m
Reservoir rock: Chalk
Geological age: Danian and Upper Cretaceous

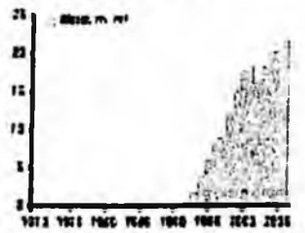
PRODUCTION

Cum. production at 1 January 2007
Oil: 84.35 m. m³
Gas: 21.08 bn. Nm³
Water: 53.18 m. m³



INJECTION

Cum. injection at 1 January 2007
Water: 107.58 m. m³



Oil: 53.8 m. m³
Gas: 8.3 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 1983, 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.

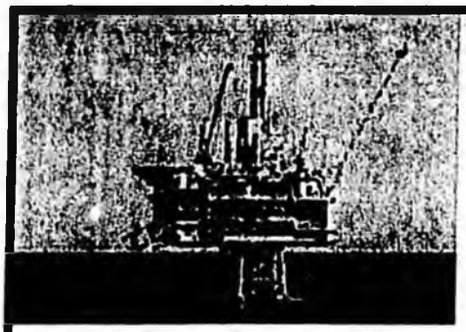
At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Ragnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

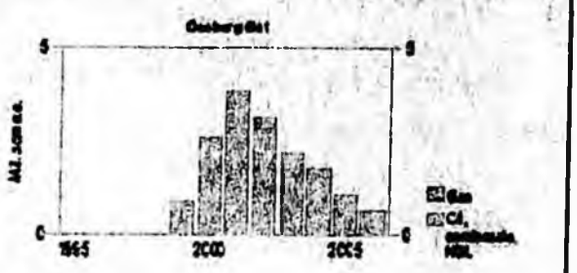
After final processing, the oil is transported to shore via the riser platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

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	1983	
Development approved	11.10.1988 by the King in Council	
On stream	06.05.1988	
Operator	Norsk Hydro Produksjon AS	
Licensees	Mobil Development Norway AS	4,70 %
	Norsk Hydro Produksjon AS	34,60 %
	Norske ConocoPhillips AS	2,40 %
	Petoro AS	38,60 %
	Statoil ASA	15,80 %
	Total E&P Norge AS	4,00 %
Recoverable reserves	Original:	Remaining 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	Estimated production in 2007:	
	Oil: 10 000 barrels/day Gas: 0,02 billion scm	
Investment	Total investment is expected to be NOK 18,2 billion (2007 values)	
	NOK 8,8 billion have been invested as of 31.12.2006 (NPV values)	
Operating organisation	Hydro	
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 100 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 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.

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October 16, 2007

MEMORANDUM

RE: Oil Company Capital Spending

Oil companies are by definition in business to make a profit. Their actions are aimed at removing or preventing any barriers to achieving increased profits. Taxes are a barrier to achieving profits and when raised serve to reduce profits and when lowered serve to increase profits. Thus, oil companies are naturally predisposed to oppose any increase in taxes. With all things being equal (which they rarely are), oil companies would preferentially invest in areas with the lowest taxes, however this is not the real world calculus.

When materiality and prospectivity are added to the investment decision criteria, oil companies quite often end up investing in countries with relatively high or above average tax rates. They do so because they believe (and often realize) that investments in those countries will provide access to new reserves and will generate significant profits. Similarly, countries that offer extraordinary potential (like Angola, Russia and Kazakhstan) are able to command a greater share of the total pie while, at the other extreme areas which have extremely favorable tax regimes (like Ireland and Morocco) still do not attract significant industry interest.

The oil companies are – rationally – resisting initiatives to increase their effective tax burdens and attempting to boil down the issue of fiscal policy and its impact on their capital investment decision making to a single factor: **the effective tax rate**. But the issue is not that simple. The oil companies must, if they are to remain in existence, do a good job at profitably replacing the reserves that they are currently producing. The number of locales in the world that offer the larger oil companies the needed level of materiality to do that are limited in number. ExxonMobil, BP, Chevron and ConocoPhillips for example, together produce over 12 million barrels of oil equivalent per day – to simply replace their production they need to find a Kuparuk size accumulation every 8 to 9 months!

The oil companies have compared Alaska's tax regime to mainly other lower 48 United States tax regimes; however, such a comparison would only be valid for a small portion of their overall investment capital spending. Lehman recently published a survey of 350 companies that showed estimated total worldwide capital spending in 2007 of just over US$300 billion of which roughly one quarter or US$77 billion would be in the United States (including Alaska). Overall, 2007 numbers represented over a 20% increase for international (i.e. non-US or Canada) spending with United States spending up slightly and Canadian spending down.

Looking at just the United States, expected 2007 spending represents an increase of 4.8% over 2006. A further breakdown of the numbers by Lehman shows that smaller

companies (those with annual spending under US$1 billion) were estimating increasing their spending by some 10+% for 2007 while the large oil companies were only expecting spending in the United States to increase 1.2%.

The Lehman data seem to be corroborated by data in the oil companies' annual reports. Gaffney, Cline & Associates reviewed annual reports for BP, Chevron, ConocoPhillips and ExxonMobil for 2002 through 2006. Where available, capital spending data overall and in the United States for the upstream sector were used. Where such geographic breakdown was not provided data for corporate spending were used to arrive at the numbers below. The key piece of information is not the absolute value, but the trend of where the main players in Alaska are spending the bulk of their investment dollar. For upstream spending BP's investments outside the United States represented 50% to 75% of their overall total. Similar numbers for Chevron were 67% to 71%, ConocoPhillips 63% to 75% and ExxonMobil 77% to 85%.

		Capital Spending ($millions)									
		2006		2005		2004		2003		2002	
BP:	US	$6,992	50%	$3,870	38%	$3,913	36%	$3,906	26%	$3,100	32%
	International	$6,526	50%	$6,367	62%	$7,095	64%	$11,286	74%	$6,559	68%
	TOTAL	$13,118		$10,237		$11,008		$15,192		$9,659	
Exxon:	US	$2,486	15%	$2,142	15%	$1,922	16%	$2,125	18%	$2,357	23%
	International	$13,745	85%	$12,328	85%	$9,793	84%	$9,863	82%	$8,037	77%
	TOTAL	$16,231		$14,470		$11,715		$11,988		$10,394	
Conoco:	Alaska	$820	9%	$748	11%	$645	12%	$570	13%	$706	22%
	US (Continental)	$2,008	21%	$891	13%	$669	12%	$848	19%	$499	15%
	International	$6,685	70%	$5,047	76%	$3,935	75%	$3,090	68%	$2,071	63%
	TOTAL	$9,513		$6,684		$5,249		$4,508		$3,276	
Chevron:	US	$4,123	32%	$2,450	29%	$1,820	29%	$1,641	29%	$1,888	30%
	International	$8,696	68%	$5,939	71%	$4,501	71%	$4,034	71%	$4,395	70%
	TOTAL	$12,819		$8,389		$6,321		$5,675		$6,283	

Moreover, the review of the annual reports show investment by these four companies in significant projects in jurisdictions that have average and marginal tax rates above those in place or proposed in Alaska.

In deciding where to invest, tax policy is one of the factors considered but is demonstrably not, in and of itself, the controlling factor.

Oil and Gas Reporting and Disclosure In Selected Countries

Focus On Cost / Field Detail Reporting

Summary

- **In the vast majority of regimes around the world companies are required to disclose detailed data**
  - Prospective (plans) and actual
  - Typically down to well / field level detail

- **Data is provided to both resource-management and fiscal/taxation authorities**
  - Intra-governmental sharing
  - Greater flow to, rather than from, fiscal authorities

- **Reporting and public disclosure are two separate issues**
  - Public reporting is common
  - Though typically in aggregated or summary form

Why Does Alaska Need To Receive Data ?

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

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

Forms Of Reporting and Sharing

- **Production and well data** - most countries have statutory req. to report core data, drawings 2-5 yr. confidentiality
  - Monthly or as completed
- **Annual or Semi-Annual field-level information**
  - Typically collected by Ministry / Regulatory Body
- **Tax returns**
  - Collected by fiscal authority
- **Intra-Governmental Sharing**
  - Degree of sharing varies by country
  - Typically greater sharing by Ministry / Regulatory Body than by fiscal authority

Public Reporting

- **Mostly in aggregated / summary form**

- **Some countries provide field-level summaries**
  - Reserves
  - Capex (capital expenditures)
    - More often as total, but sometimes as annual time series

- **Opex rarely disclosed at field-level, although subscription services do provide this**
  - Data quality dependent upon various sources, including "oil company guidance"
  - Sometimes occurs in stock market documentation released by (usually) smaller companies

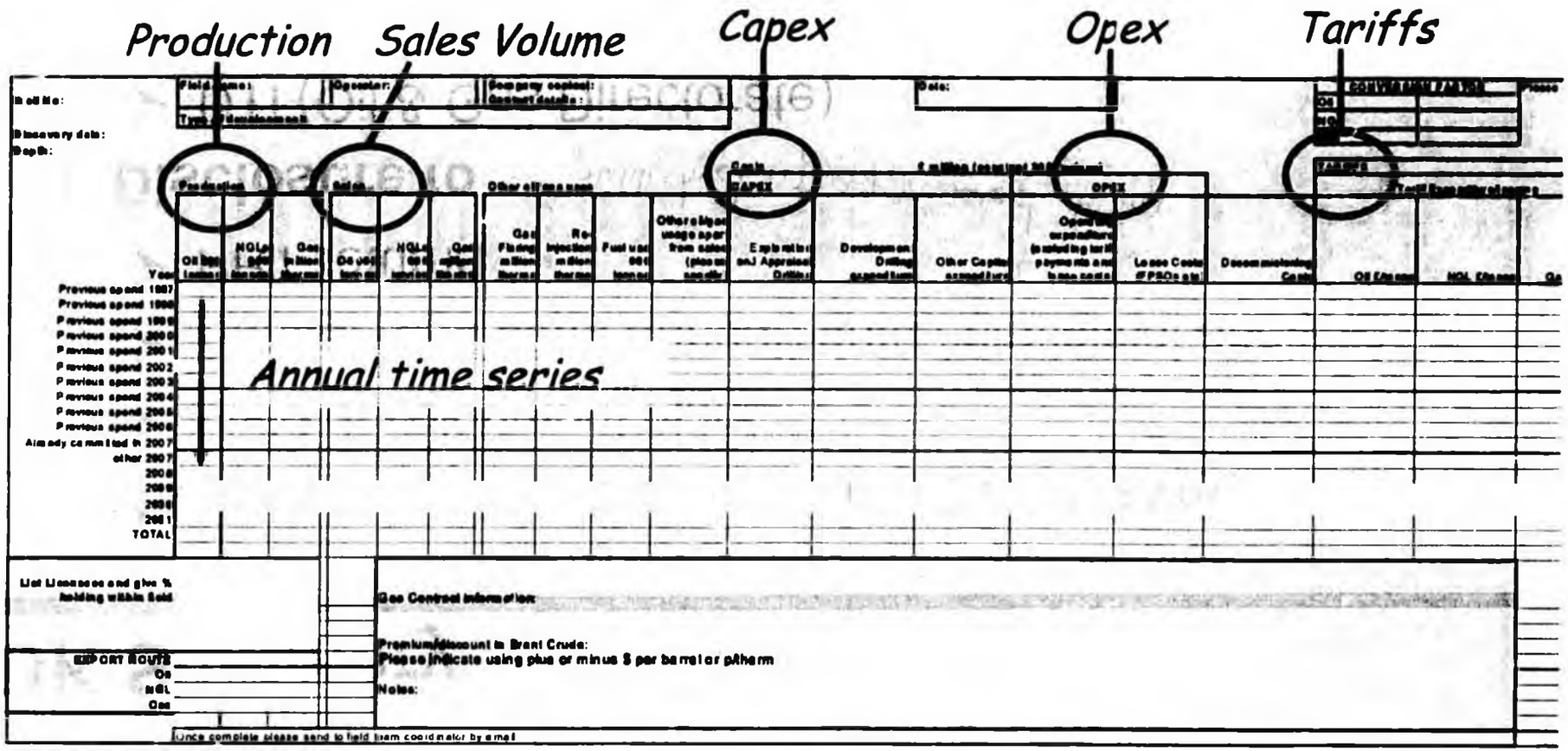
Examples Of Data Disclosure (Production and Cost Focus)

UK Summary

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

United Kingdom

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



United Kingdom

Annual UKCS Income and Expenditure summarized on an annual basis

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

Sales — *Opex* — *Capex*

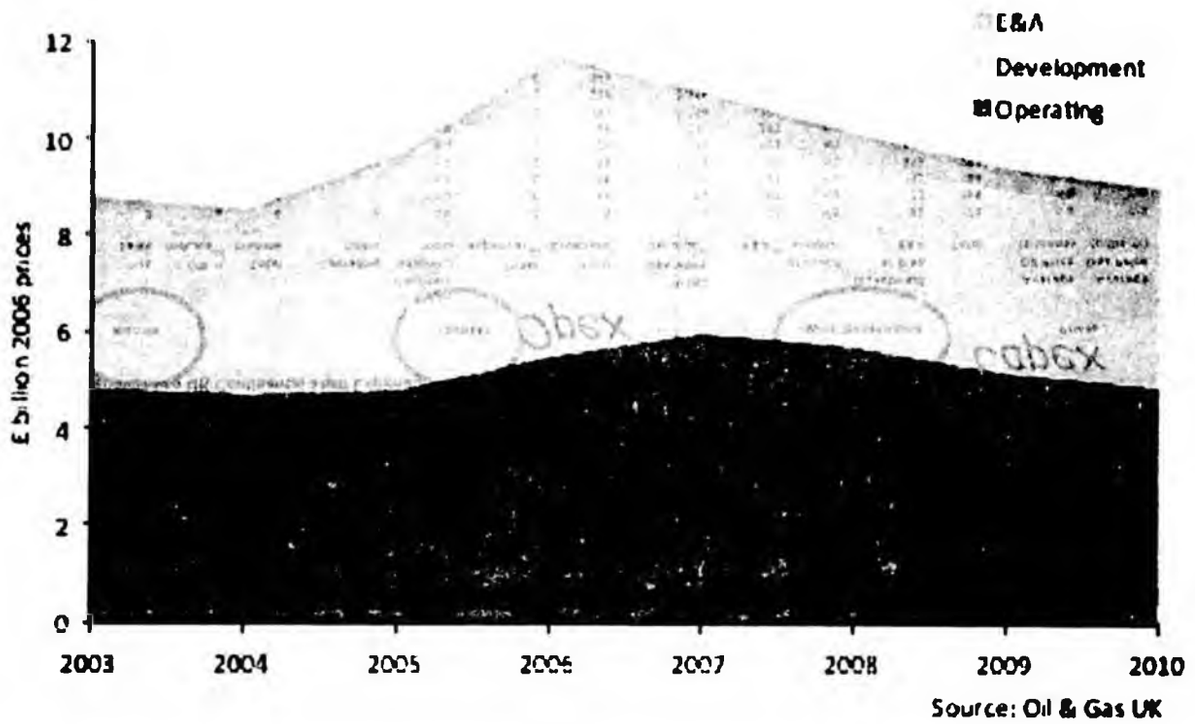
	Income					Expenses					Capital Expenditure				Prices		
	Oil Sales	NGL Sales	Gas Sales	Other income[1]	Total income	Operating Costs	of which decommissioning costs	Other expenses[2]	Total Expenses	Gross Operating Surplus[3]	E&A[4]	of which ...	Investment other than E&A	Total	Average Oil Price (£/tonne)	Average Gas Price (p/therm)	GDP Deflator (2003=100)
1970	0	0	2	4	6	6	n/a	0	6	-2	33	n/a	65	78	n/a	n/a	9.9
1971	0	0	52	8	60	11	n/a	0	11	70	57	n/a	73	130	n/a	n/a	10.6
1972	0		114	9	124	16	n/a	0	16	110	43	n/a	112	164	n/a	n/a	11.7
1973	0	3	133	11	148	18	n/a	0	18	129	60	n/a	218	284	n/a	n/a	12.6
1974	0	3	168	21	194	20	n/a	0	20	170	103	n/a	696	797	n/a	n/a	14.4
1975	43	10	193	29	277	40	n/a	0	40	231	242	n/a	1,374	1,616	n/a	n/a	18.3
1976	624	31	250	21	924	133	n/a	0	168	794	301	n/a	2,070	2,372	n/a	1.8	21.1
1977	2,197	29	317	23	2,563	207	n/a	0	207	2,356	278	n/a	2,167	2,443	n/a	2.1	24.0
1978	2,771	66	432	13	3,266	344	n/a	0	348	2,904	301	n/a	2,170	2,481	n/a	3.1	26.8
1979	5,647	83	530	44	6,276	532	n/a	18	610	5,767	241	n/a	2,664	2,906	n/a	3.3	30.7
1980	8,719	133	647	82	9,600	602	n/a	34	720	8,864	378	n/a	2,308	2,707	n/a	4.5	36.7
1981	12,200	130	843	114	13,290	1,317	n/a	41	1,048	12,235	663	n/a	2,047	3,007	n/a	6.5	40.0
1982	14,129	212	944	163	15,447	1,333	n/a	73	1,082	14,174	678	n/a	3,210	3,004	142.0	7.4	43.9
1983	16,490	528	1,117	161	18,930	1,496	n/a	67	1,642	16,787	963	n/a	2,883	3,846	140.3	8.4	46.3
1984	19,827	669	1,283	286	22,166	1,733	n/a	62	1,790	20,318	1,284	n/a	3,100	4,664	164.0	13.5	48.4
1985	19,264	682	1,739	384	21,600	2,249	n/a	76	2,024	18,664	1,446	n/a	2,794	4,290	166.3	11.9	51.1
1986	8,860	386	1,827	485	11,070	2,144	n/a	57	2,201	9,476	1,035	n/a	2,418	3,447	73.3	12.6	52.9
1987	8,613	368	1,553	533	12,004	2,137	n/a	65	2,103	10,203	860	n/a	2,044	3,048	81.7	12.4	55.7
1988	7,384	240	2,246	566	10,500	2,340	n/a	66	2,110	8,130	1,129	n/a	2,136	3,266	65.4	13.1	59.2
1989	7,216	272	2,187	547	10,238	2,333	n/a	47	2,884	7,033	1,182	n/a	2,836	3,617	81.1	14.2	63.6
1990	8,432	277	2,377	431	11,481	2,692	n/a	46	2,838	8,852	1,637	n/a	3,474	5,110	86.5	14.3	68.6
1991	7,070	386	2,660	476	11,496	3,206	n/a	66	3,064	6,373	1,981	n/a	5,161	7,047	66.3	16.9	73.0
1992	7,430	303	3,016	626	11,446	3,312	n/a	63	3,366	6,306	1,626	n/a	5,420	6,866	61.9	16.8	76.0
1993	8,115	421	3,888	609	12,800	3,551	n/a	47	3,700	8,191	1,212	n/a	4,661	5,874	66.6	18.8	78.0
1994	8,864	521	3,536	974	14,883	3,663	n/a	45	3,900	10,437	919	193	3,671	4,900	77.6	18.3	79.2
1995	9,887	614	4,141	168	15,882	3,873	n/a	37	3,860	11,882	1,081	234	4,396	5,446	81.1	18.3	81.4
1996	11,860	749	5,296	1,243	19,166	3,978	n/a	31	4,066	15,127	1,097	133	4,364	5,461	97.3	16.6	84.2
1997	10,327	702	5,264	1,279	17,601	4,150	n/a	34	4,184	13,377	1,194	174	4,283	5,467	87.4	16.7	86.6
1998	7,407	561	5,312	1,483	14,606	4,193	n/a	111	4,001	10,631	762	129	4,396	5,166	68.6	16.2	88.9
1999	10,257	727	5,231	1,436	17,460	4,249	n/a	262	4,631	12,826	417	64	3,603	3,626	93.3	13.7	90.9
2000	16,276	1,117	6,836	1,466	25,466	4,363	n/a	168	4,440	21,326	349	43	3,760	3,606	138.1	16.6	92.1
2001	13,646	962	6,143	1,436	24,166	4,347	n/a	49	4,998	19,708	433	34	3,675	3,666	135.7	19.3	94.1
2002	13,624	894	6,799	1,307	24,116	4,594	n/a	48	4,043	19,476	389	46	3,198	3,566	133.6	18.4	97.0
2003	13,366	1,130	7,684	1,639	26,002	4,490	n/a	6	4,696	19,866	334	42	3,412	3,746	130.5	17.4	100.0
2004	13,477	1,268	7,443	178	23,064	4,554	249	67	4,761	19,613	396	37	3,362	3,666	164.3	21.8	102.6
2005	16,696	1,484	8,902	481	28,066	5,113	412	128	5,241	23,482	443	34	4,371	4,889	215.0	27.6	104.9

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

United Kingdom

Medium-term forecasts derived from annual returns

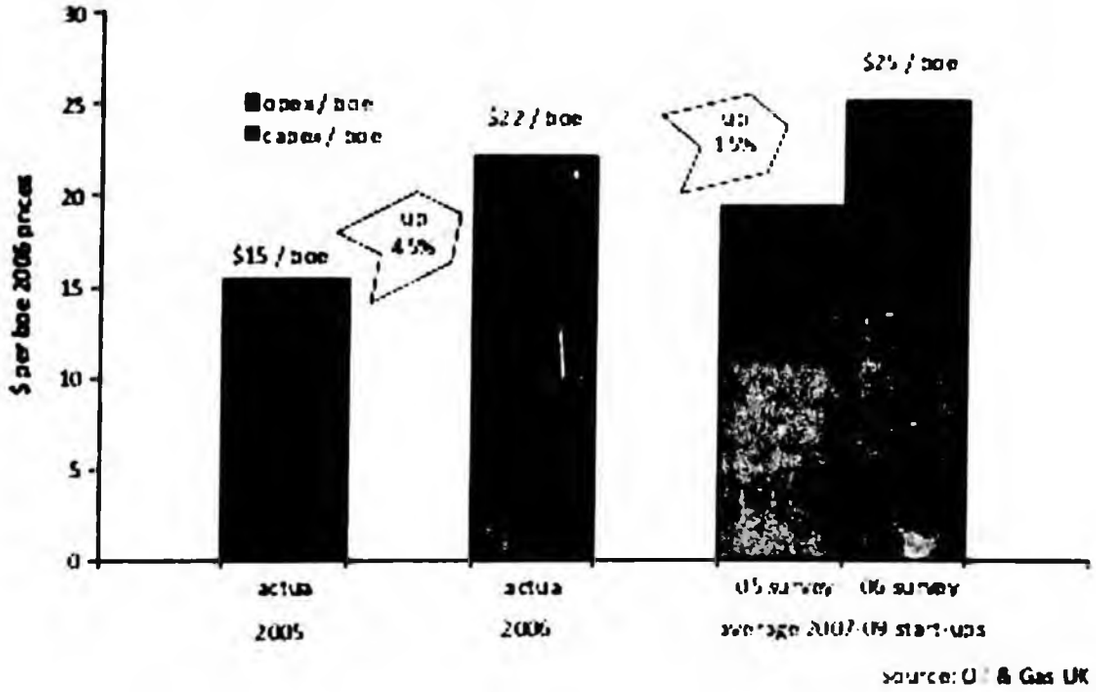
Figure 30: UKCS Expenditure Forecast 2003-2010



United Kingdom

Cost trends

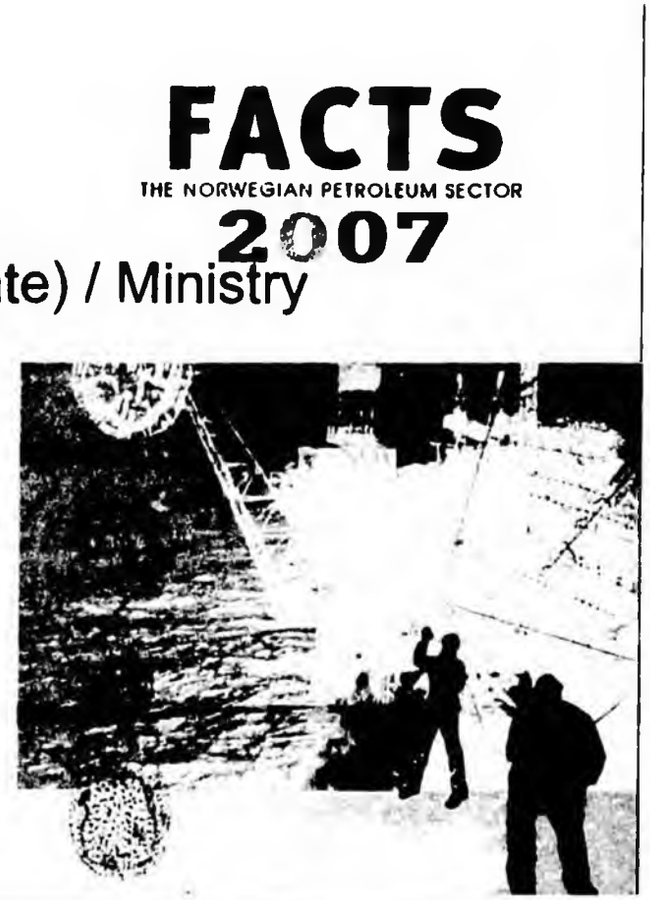
Figure 33: UKCS New Developments' Unit Technical Cost 2005-2009



Norway Summary

reporting to: Norwegian Petroleum Directorate

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



Norway

Field / discovery listing of resource volumes

Tilstedeværende ressursar i felt
In-place resources in fields

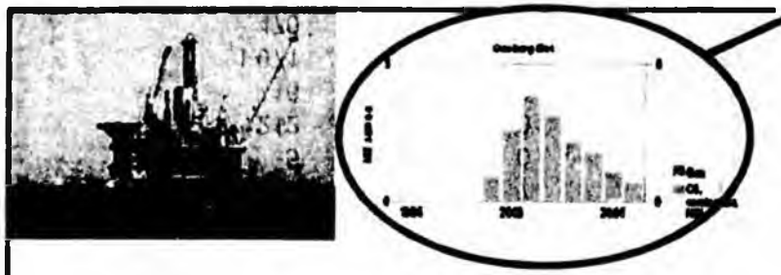
OLJEDIREKTORATET

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

Norway

Detail on field-by-field basis

Production forecast by year



Oseberg Øst

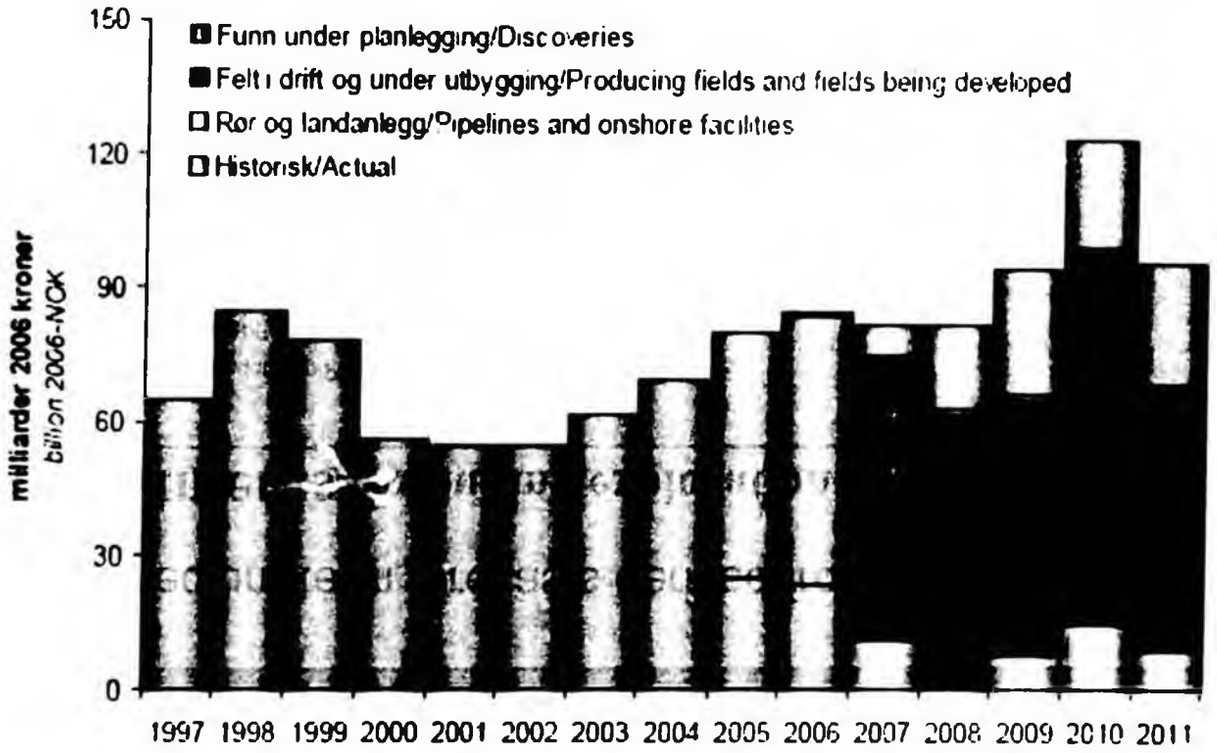
Reserves and EUR

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

Norway

Medium-term forecasts derived from annual returns

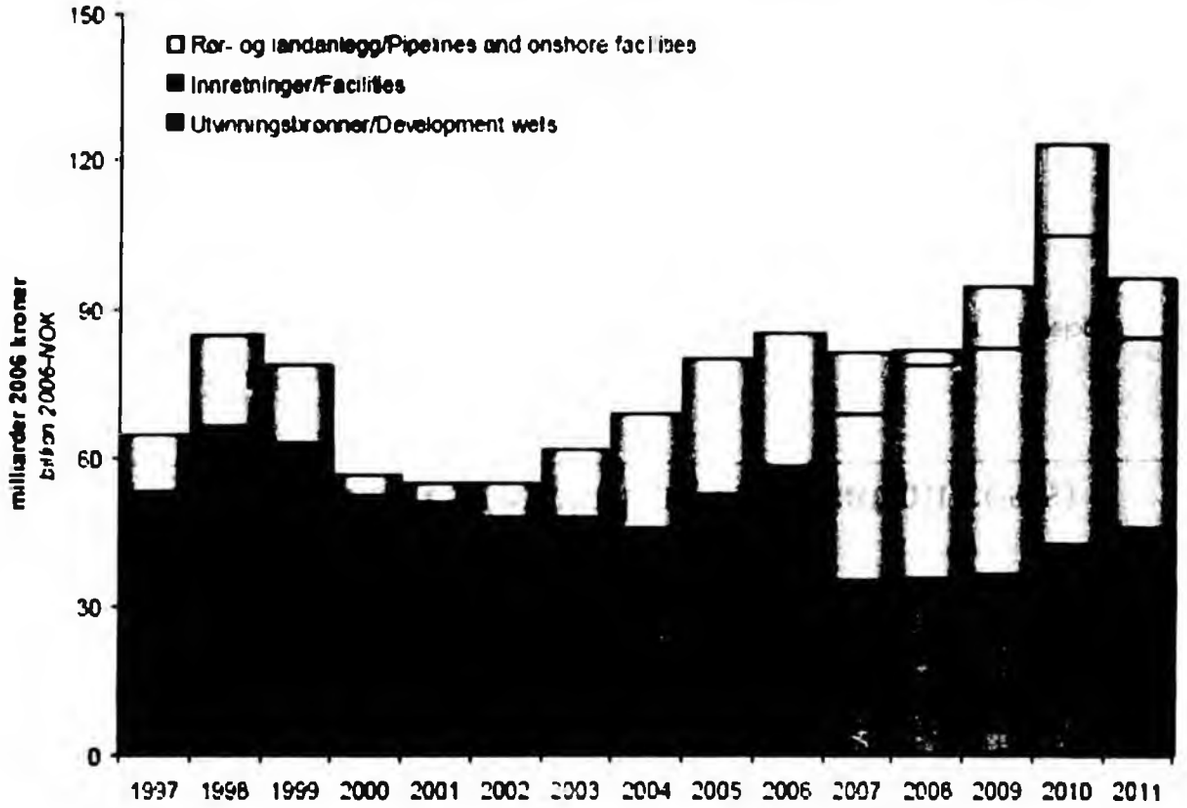
Investments (excluding exploration costs)



Norway

Medium-term forecasts derived from annual returns

Investments (excluding exploration costs)



Norway

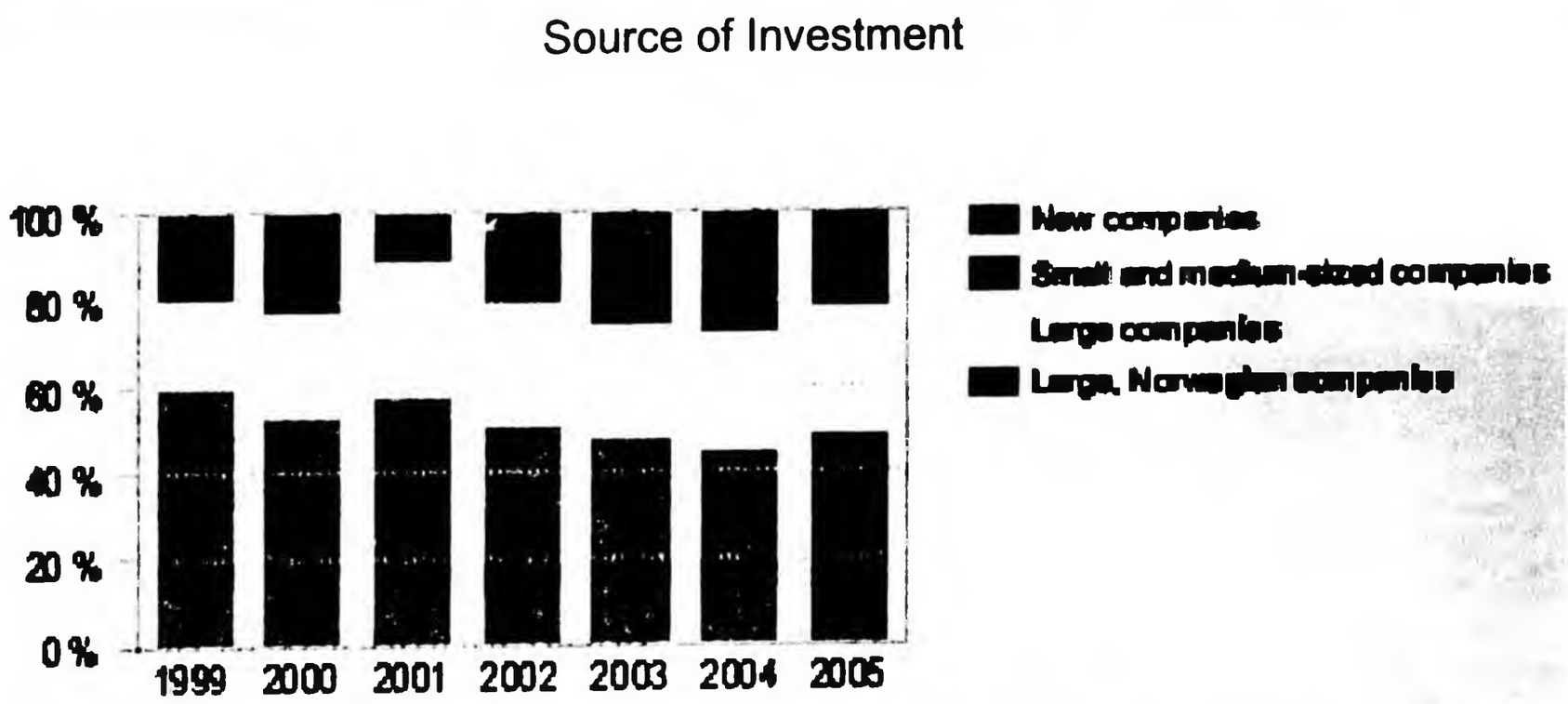


Figure 3.8 Exploration costs in production licences on the Norwegian continental shelf, distributed according to the size of the companies

(Source: Norwegian Petroleum Directorate)

Denmark Summary

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

Denmark

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

Table 7.4 Investments, DKK million, nominal prices

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

*Estimate

Denmark

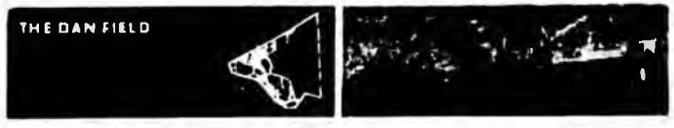
.. and projected

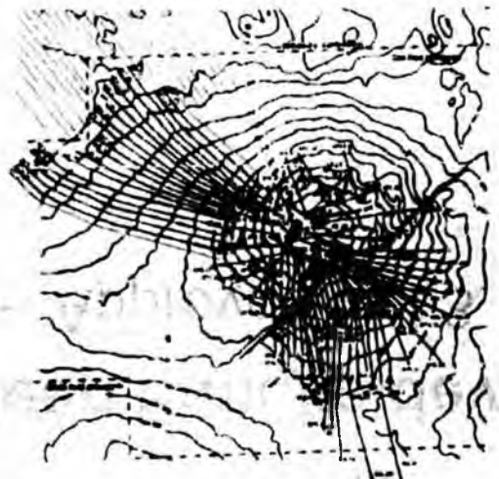
Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

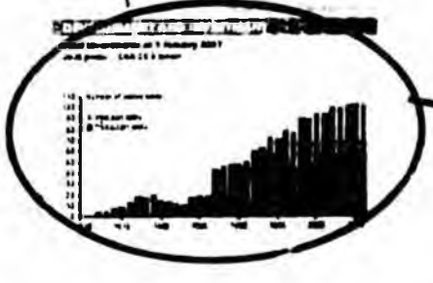
	2007	2008	2009	2010	2011
Ongoing and approved					
Adda	-	0.1	0.6	-	-
Alma	-	0.6	0.5	-	-
Boje	-	-	-	0.8	-
Cecilie	-	-	-	-	-
Dagmar	-	-	-	-	-
Dan	0.9	0.6	-	-	-
Ely	0.3	1.6	-	-	-
Gorm	0.1	0.0	-	-	-
Halfdan	2.0	0.9	0.1	-	-
Harald	0.0	0.1	-	-	-
Kraka	0.3	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.1	-	-	-	-
Ragnar	-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

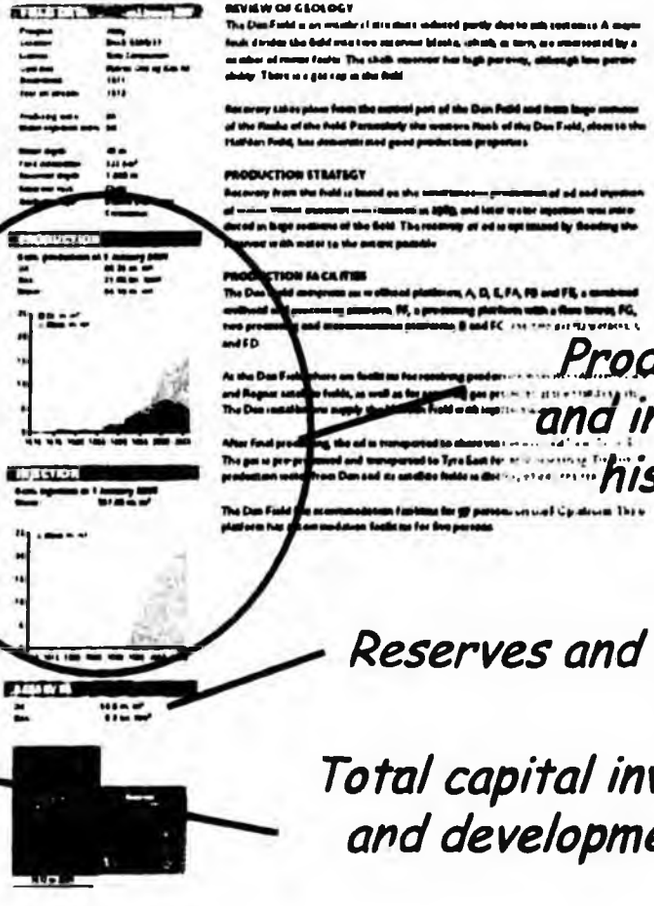
Denmark

Detail on field-by-field basis









Production and injection history

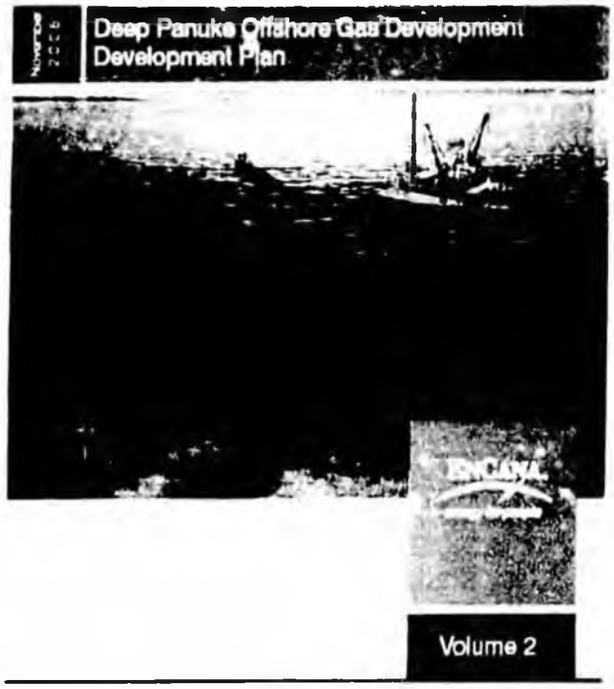
Reserves and EUR

Total capital investment and development drilling

Nova Scotia Summary – Canada Nova Scotia Offshore Petroleum Board

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

Nova Scotia Deep Panuke



Includes sales gas forecast …

Table 6.1 Sales Gas Forecast

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