Marsha Davis - 10-29-2007

Hypothetical example

net tax -

say tax rate = 20%

spend $100 minus 20% ($20) = cap. invest. of $80
State spent $20

① deduct in net tax

② + get it as capital credit +

Higher tax rate = higher net present value to producer

" " " = more of an incentive for new developments (but doesn't enhance state revenue as much progressivity)

AS 43.55.160 (cont.)

- (2) bill is clearer and more specific on when a producer may or may not use lease expenditures for operations at one location as deductions for oil and gas produced at another location
- These rules are necessary to implement the different tax treatments of different areas and fields (Cook Inlet ceilings, North Slope floor, tax credit under AS 43.55.024(a))

13

AS 43.55.160 (cont.)

- For instance:
- (i) To avoid undercutting the tax floor, deductions may not be "exported" from units subject to the tax floor (AS 43.55.160(f)(2))
- (ii) To avoid double-dipping re: Cook Inlet tax ceilings, deductions must first be used up in Cook Inlet and may not be shielded by the ceilings (AS 43.55.160(h) and (i))

14

AS 43.55.165 (bill secs. 56-59, 64) Lease Expenditures

AS 43.55.165(a) and (b) are rewritten and reorganized:

- (1) for more clarity
- (2) to limit lease expenditures to only what the Department of Revenue allows by regulation

15

Lease Expenditures (continued)

- AS 43.55.165(c) and (d) are repealed.
- Those provisions allowed the Department to substitute cost billings under unit operating agreements in place of the general standards for determining lease expenditures.

16

Lease Expenditures (continued)

- AS 43.55.165(e): the list of *excluded* costs is expanded:
- par. (7) – costs arising from violation of law or noncompliance with lease or permit obligation
- par. (8) – all dismantlement, removal, & restoration costs (costs are prorated for past production under current law)

17

Lease Expenditures Exclusions (cont.)

- par. (19) - repair or replacement of facilities or equipment associated with an unscheduled drop in production or an oil spill or unpermitted release
- par. (20) – crude oil topping plant (but deduction is allowed for value added of product used in lease operations)

18

Tax Credits under AS 43.55.023 Bill secs. 26-31, 65

Changes to .023(a) – qualified capital investment expenditure credits :

- Only 50% of a credit may be used the first year
- For exploration, requirements are conformed to changes in .025 credits (see below)

18

Tax Credits under AS 43.55.023 (continued)

Changes to .023(a) (continued)

- Credits for capital expenditures in a unit subject to the tax floor may be applied only against tax on oil and gas production from that or another unit subject to the tax floor

20

Tax Credits under AS 43.55.023 (continued)

Change to .023(b) – carried-forward annual loss credit :

- No carry-forward for unused lease expenditures for units subject to the tax floor

21

Tax Credits under AS 43.55.023 (continued)

Change to .023(d) – transferable tax credit certificates:

- Two certificates will be issued, each for half of the credit
- One certificate cannot be used until the next year

22

Tax Credits under AS 43.55.023 (continued)

New subsection .023*(l)* :

- Makes clear that a tax-exempt entity may not obtain a transferable tax credit certificate

23

Tax Credits under AS 43.55.023 (continued)

AS 43.55.023(i) is repealed:

- This eliminates the transitional investment expenditure credits for investments that were made during the five years before April 1, 2006.

24

Tax Credits under AS 43.55.025 Bill secs. 36-44

- Sec. 36 - Existing 2016 sunset is uniformly applied
- Secs. 37 & 43 - Exploration well credit expanded to delineation wells within 2 drilling seasons (rather than being limited to discovery well or dry hole)
- Sec. 37 - Well must be completed or abandoned, not just suspended, before credit may be claimed

25

Tax Credits under AS 43.55.025 (continued)

- Sec. 37 - Costs excluded if due to gross negligence or health/safety/ environmental violation
- Sec. 38 – Clearer definition of requirement for new exploration target; 3-mile requirement deleted for Cook Inlet; DNR evaluation required in advance and after drilling

26

Tax Credits under AS 43.55.025 (continued)

- Sec. 39 – Data submission requirements are more specific
- Sec. 39 – Well data confidentiality limited to 24 months
- Sec. 39 - Two certificates will be issued, each for half of the credit; one certificate cannot be used until the next year

27

Tax Credits under AS 43.55.025 (continued)

- Sec. 39 - Makes clear that basic information about tax credit is public
- Sec. 40 - Makes clear that a tax-exempt entity may not transfer a tax credit certificate
- Sec. 44 - New five percent tax credit available for old seismic data if DNR determines that acquiring the data for public distribution is in state's interest

28

State Purchase of Tax Credits Certificates – Bill secs. 45 & 63

- New AS 43.55.028 establishes oil and gas tax credit fund to purchase credit certificates from explorers or small producers that have no tax liability to apply credits against
- Funded by appropriation of a percentage of production tax revenues
- Replaces existing cash refund authority under AS 43.55.023(f) (repealed by bill)

29

State Purchase of Tax Credits Certificates (continued)

- Retains existing criteria for refunds except eliminates $25 million maximum

30

Payment of the Tax
Bill secs. 22-25, 51

- Current system of monthly installment payments and final payment on March 31 is retained
- Installment payments now take account of the tax floor for units subject to the tax floor and also take account of Cook Inlet tax ceilings
- Installment payments do not take account of progressivity rate

31

Payment of the Tax
(continued)

- AS 43.55.110(f), Bill sec. 51 – Gives express authority to Department to require tax payments to be made electronically

32

Reporting Requirements
AS 43.55.030, 43.55.040

- Bill sec. 46 – Makes clear that every oil or gas producer must file an annual return, whether or not tax is due
- Bill sec. 46 - Expands the list of specific information requirements for returns (note: Department retains general authority to require more information)

33

Reporting Requirements
(continued)

- Bill secs. 47 & 49 – Additional penalty of up to $1,000 per day for late filing or nonfiling of required returns or reports
- Bill sec. 48 – Requires explorers or producers to file an annual statement on expenditures (or adjustments) even if no oil or gas is produced during the year

34

Reporting Requirements
(continued)

- Bill sec. 48 – Makes clear that the Department may also require monthly reports from producers, explorers, and operators
- Bill sec. 49 – Adds express authority for the Department to require reporting of forward-looking information for revenue forecasting purposes

35

Reporting Requirements
(continued): Bill sec. 51

- AS 43.55.110(e) – Gives express authority to Department to require returns and reports to be filed electronically

36

Confidential and Public Information

- AS 38.05.035, Bill sec. 2 – broad authority for DNR to share oil and gas lease related information with DOR for purposes of administering the production tax
- AS 43.05.230, Bill sec. 14 – broad authority for DOR to share production tax related information with DNR

37

Confidential and Public Information (continued)

- Under both provisions, confidential information is still confidential
- AS 43.55.890, Bill sec. 61 – Makes clear that Department of Revenue may publish extensive production tax information aggregated among at least three producers or explorers

38

Additional Administrative Improvements

- AS 39.25.110, Bill sec. 10 – oil and gas auditors placed in exempt service
- Transition provision, Bill sec. 67 – current employees may opt to stay in union
- AS 43.05.260, 43.55.075, Bill secs. 14, 50 – statute of limitations for production tax is six years, not three years

39

Additional Administrative Improvements (continued)

- AS 43.55.075(b), Bill secs. 1, 50 - Legislative confirmation of Department of Revenue's interpretation of statute of limitations as applied to events that retroactively change amount of production tax or credit: period of limitations begins to run when a return is filed reflecting the change

40

Additional Administrative Improvements (continued)

- AS 43.55.110(g), Bill sec. 51 – Gives express authority to the Department of Revenue to issue advisory bulletins interpreting production tax statute and regulations for guidance of taxpayers and others; non-binding unless Department provides otherwise

41

Transition, Applicability, and Effective Dates

- Bill secs. 66, 72 – Most substantive changes in the production tax are prospective beginning Jan. 1, 2008
- Bill secs. 66, 71 – Changes to lease expenditure exclusions and use of unit operating agreements for lease expenditures are retroactive to April 1, 2006

42

Transition, Applicability, and Effective Dates (continued)

- Bill secs. 66, 71 – Statute of limitations extension applies to still-open periods and retroactive to April 1, 2006
- Bill secs. 66, 71 – Clarification that tax-exempt entities may not transfer tax credits applies back to beginning of the respective tax credit provisions

43

Transition, Applicability, and Effective Dates (continued)

- Bill sec. 73 – Most other provisions of the bill take effect immediately
- Bill secs. 68, 70 – DOR and DNR may start developing regulations immediately, and regulations may be retroactive to applicability date of the statutory provisions they implement

44

Oil and Gas Reporting and Disclosure In Selected Countries

Focus On Cost / Field Detail Reporting

Summary

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

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

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

Why Does Alaska Need To Receive Data ?

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

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

Forms Of Reporting and Sharing

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

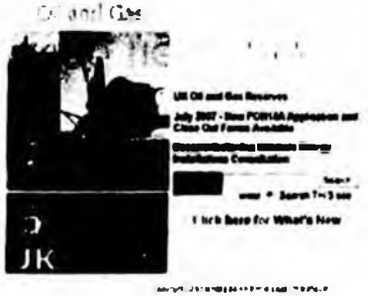
Public Reporting

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

Examples Of Data Disclosure (Production and Cost Focus)

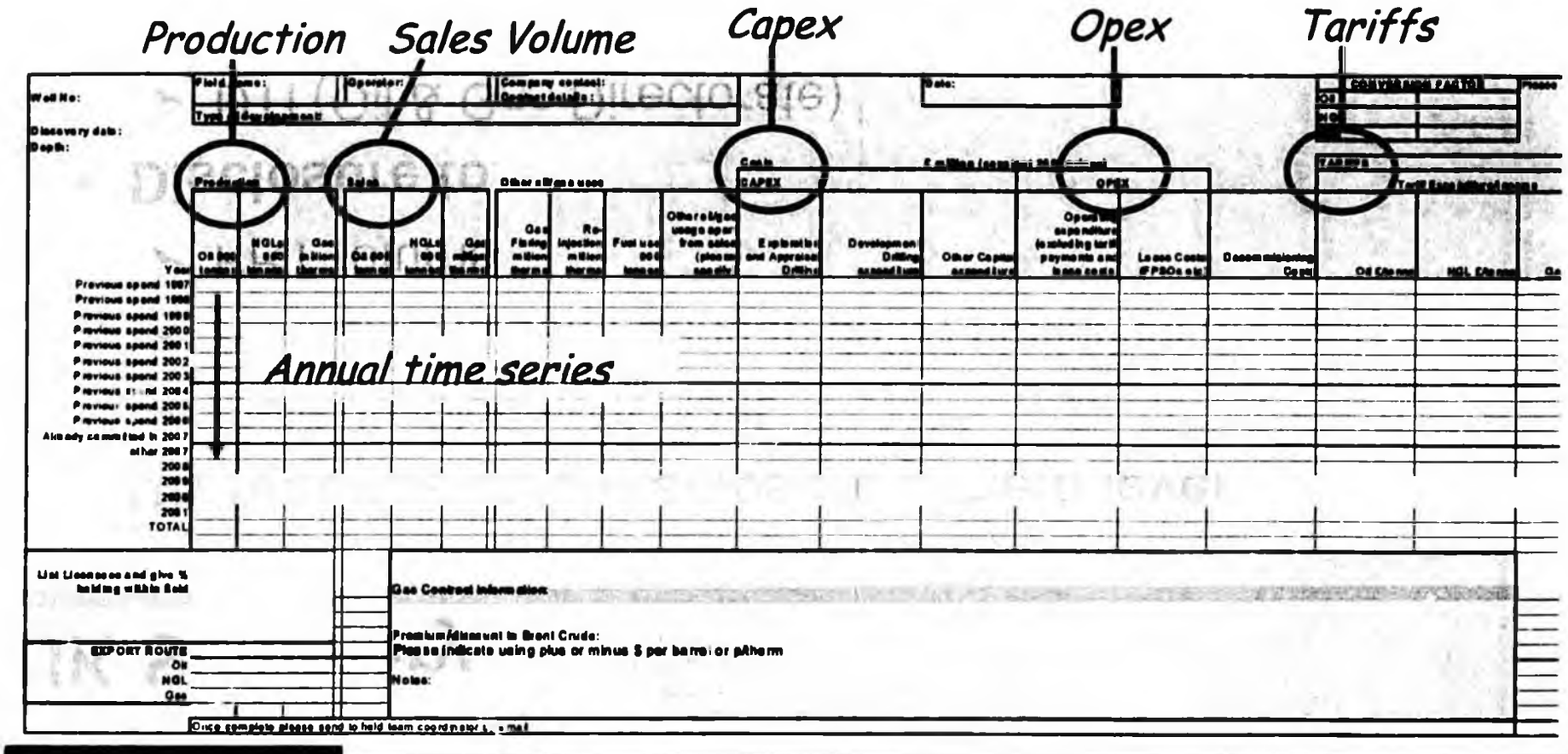
UK Summary

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



United Kingdom

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



United Kingdom

Annual UKCS Income and Expenditure summarized on an annual basis

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

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

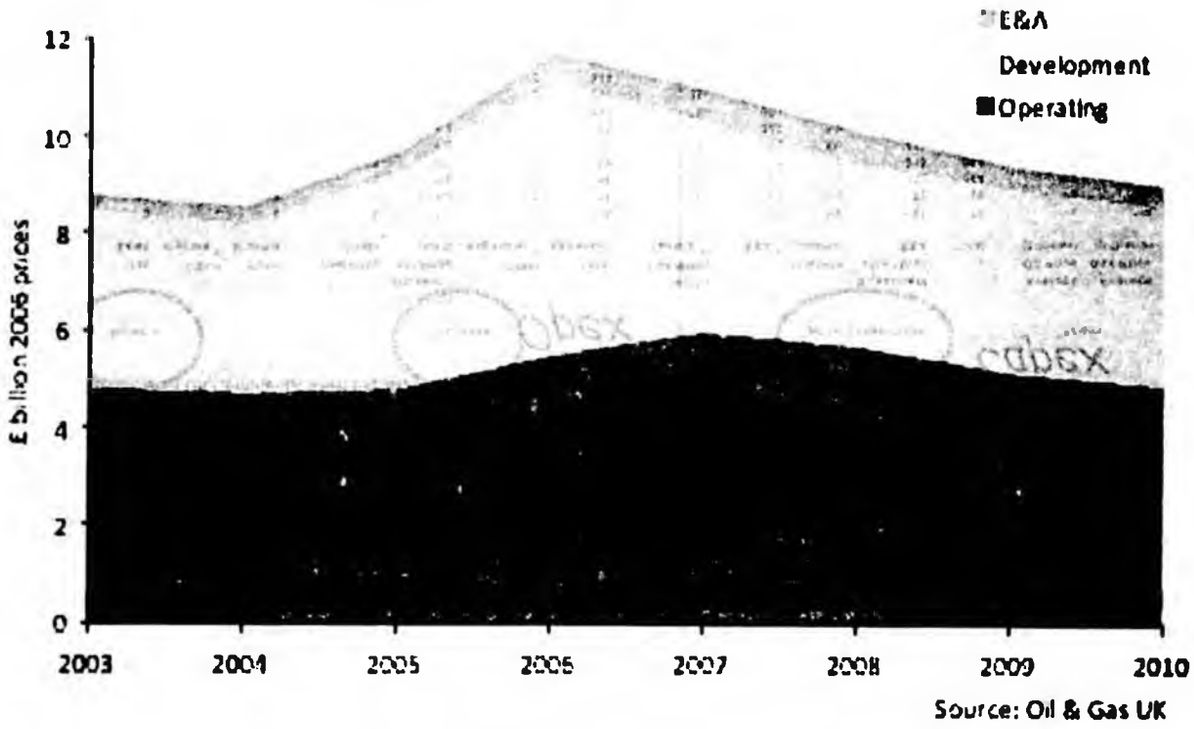
	Oil Sales	NGL Sales	Gas Sales	Other Income(1)	Total Income	Operating Costs	of which decommissioning costs	Other expenses(2)	Total Expenses	Gross Operating Surplus(3)	E&A(4)	of which seismic	Investment other than E&A	Total	Average Oil Price (£/tonne)	Average Gas Price (p/therm)	GDP Deflator (2005=100)
1970	0	0	2	4	6	6	n/a	0	6	-2	33	n/a	85	78	n/a	n/a	9.9
1971	0	0	62	5	66	11	n/a	0	11	76	67	n/a	72	139	n/a	n/a	10.8
1972	0		114	8	124	15	n/a	0	15	110	43	n/a	113	164	n/a	n/a	11.7
1973	0	3	133	11	146	18	n/a	0	18	129	48	n/a	216	264	n/a	n/a	12.6
1974	0	3	166	21	190	20	n/a	0	20	170	155	n/a	[illegible]	787	n/a	n/a	14.4
1975	41	10	193	28	277	44	n/a	0	44	231	242	n/a	1,374	1,616	n/a	n/a	16.3
1976	624	21	288	21	954	133	n/a	0	160	794	301	n/a	2,670	2,972	n/a	1.9	21.1
1977	2,197	29	317	23	2,565	297	n/a	0	307	2,266	378	n/a	2,167	2,462	n/a	2.1	24.0
1978	2,77[illegible]	36	432	12	3,266	344	n/a	0	344	2,924	261	n/a	2,170	2,431	n/a	3.1	26.8
1979	5,641	63	538	44	6,276	632	n/a	16	648	5,767	241	n/a	2,564	2,806	n/a	3.8	30.7
1980	8,719	123	547	62	9,450	692	n/a	34	726	8,654	370	n/a	2,388	2,767	n/a	4.8	36.7
1981	12,264	176	643	114	13,200	1,317	n/a	41	1,063	12,206	613	n/a	2,647	3,067	n/a	6.5	40.8
1982	14,125	312	966	183	15,647	1,339	n/a	73	1,442	14,174	678	n/a	3,669	3,984	142.8	7.4	43.9
1983	16,496	521	1,117	168	18,020	1,496	n/a	67	1,662	16,787	893	n/a	2,883	3,646	148.3	8.4	46.3
1984	19,827	669	1,203	256	22,100	1,733	n/a	63	1,790	23,396	1,381	n/a	3,169	4,484	164.9	10.8	48.4
1985	19,264	692	1,739	384	21,900	2,249	n/a	76	3,024	19,664	1,441	n/a	2,794	4,299	168.3	11.9	51.1
1986	8,069	306	827	455	11,070	2,144	n/a	67	2,211	8,476	1,631	n/a	2,419	3,447	73.3	12.6	52.9
1987	8,813	358	1,193	633	12,004	2,137	n/a	66	2,102	13,233	869	n/a	2,644	3,948	81.7	12.4	66.7
1988	7,384	248	2,248	600	10,290	2,348	n/a	68	2,418	8,126	1,128	n/a	3,126	4,266	63.4	13.1	69.2
1989	7,214	272	2,187	547	10,230	2,333	n/a	67	2,400	7,831	1,182	n/a	2,036	5,817	61.1	14.2	63.6
1990	8,435	277	2,277	436	11,401	2,602	n/a	41	2,611	8,882	1,627	n/a	3,478	5,116	84.8	14.3	68.6
1991	7,078	388	2,568	476	11,496	3,296	n/a	68	3,064	8,372	1,966	n/a	5,101	7,067	66.3	18.8	73.6
1992	7,436	383	3,016	626	11,448	3,312	n/a	63	3,866	8,289	1,464	n/a	6,438	8,008	61.8	18.8	76.0
1993	8,116	523	3,368	609	12,800	3,661	n/a	47	3,709	8,191	1,213	n/a	4,661	6,874	65.0	18.2	78.0
1994	8,944	528	3,838	974	14,082	3,063	n/a	45	3,088	13,431	930	132	3,871	4,800	77.8	16.3	79.2
1995	9,881	614	4,161	166	15,862	3,073	n/a	37	3,080	11,882	1,088	234	4,398	5,440	81.1	16.3	81.4
1996	11,866	749	4,298	1,241	18,166	3,078	n/a	31	4,000	15,127	1,097	133	4,364	5,461	87.3	16.6	84.2
1997	10,827	733	5,264	1,279	17,881	4,153	n/a	34	4,164	13,377	1,184	131	4,283	5,467	87.4	16.7	86.6
1998	7,467	681	5,313	1,483	16,868	4,183	n/a	111	4,061	13,831	762	129	4,090	5,768	59.8	16.2	88.9
1999	13,257	727	5,231	1,436	17,446	4,249	n/a	262	4,631	12,926	417	66	3,663	3,838	83.3	13.7	90.9
2000	16,276	1,117	6,634	488	25,406	4,383	n/a	156	4,488	21,320	348	43	2,766	3,806	136.1	16.8	92.1
2001	13,646	963	8,143	435	24,106	4,347	n/a	49	4,090	19,706	423	34	3,076	3,000	125.7	19.2	94.1
2002	13,629	894	8,199	387	24,110	4,596	n/a	48	4,643	19,476	359	46	3,696	3,900	123.8	16.4	97.0
2003	13,969	1,136	7,884	1,039	20,982	4,406	n/a	8	4,094	19,890	334	42	3,412	3,700	133.8	17.4	100.0
2004	13,477	1,288	7,443	179	23,804	4,884	748	67	4,781	19,643	395	37	3,702	3,098	164.8	21.3	102.6
2005	16,866	1,484	8,932	481	28,890	5,193	442	128	6,241	22,482	413	34	4,371	4,881	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

United Kingdom

Medium-term forecasts derived from annual returns

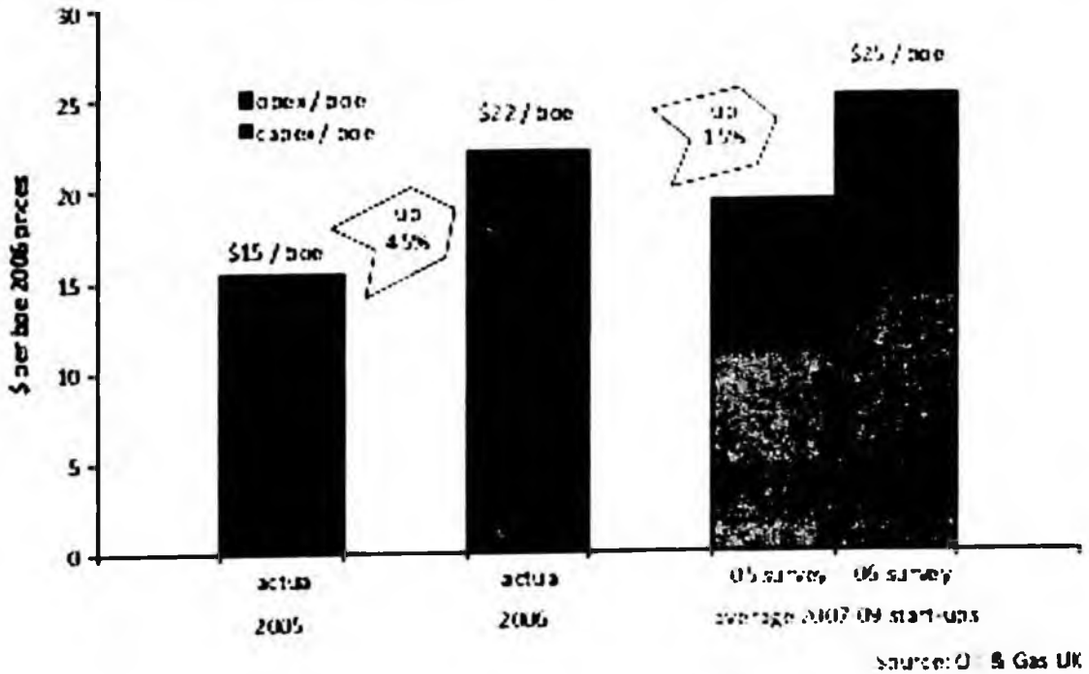
Figure 30: UKCS Expenditure Forecast 2003-2010



United Kingdom

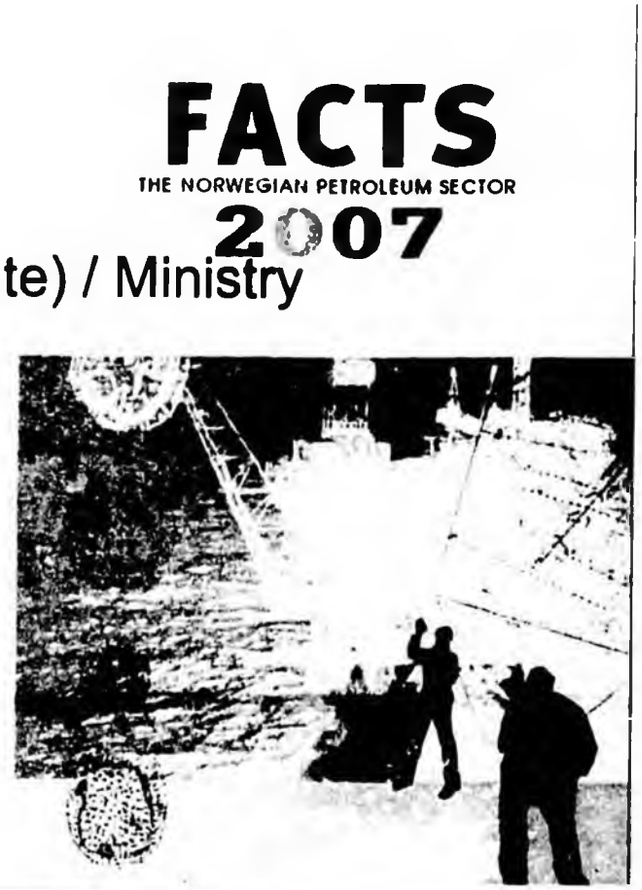
Cost trends

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



Norway Summary

- **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

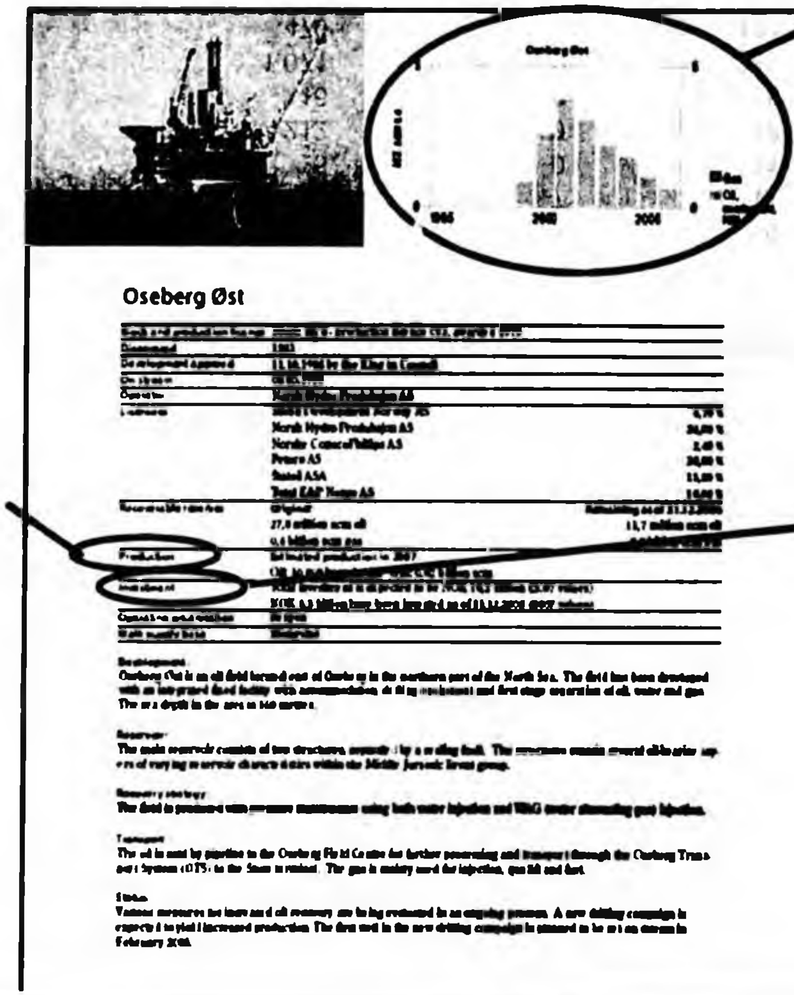
Tilstedeværende ressursar i felt
In-place resources in fields

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

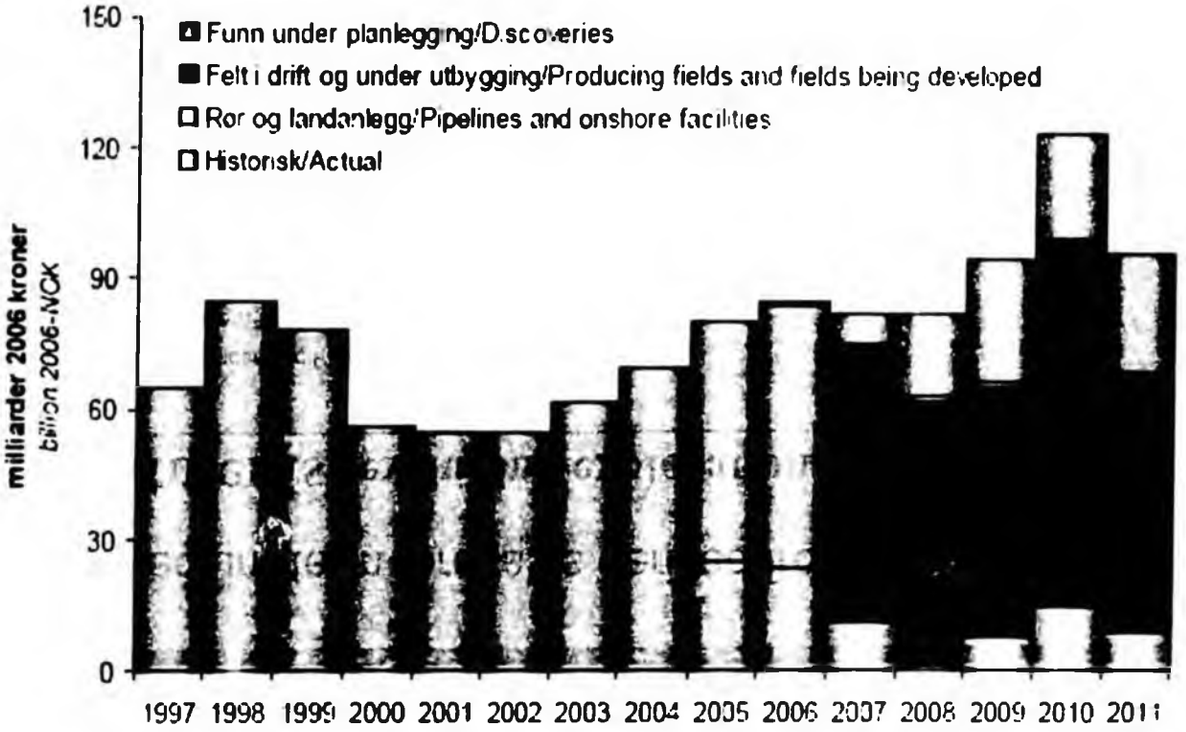
Reserves and EUR

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

Norway

Medium-term forecasts derived from annual returns

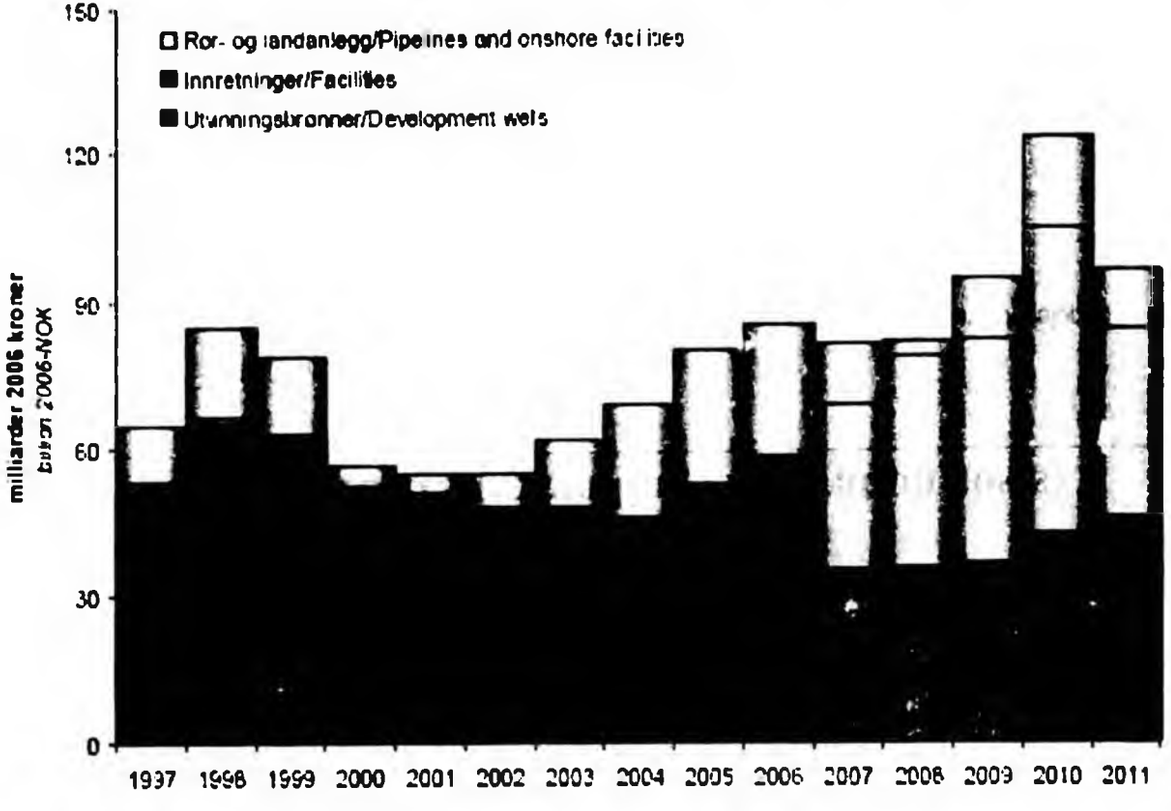
Investments (excluding exploration costs)



Norway

Medium-term forecasts derived from annual returns

Investments (excluding exploration costs)



Norway

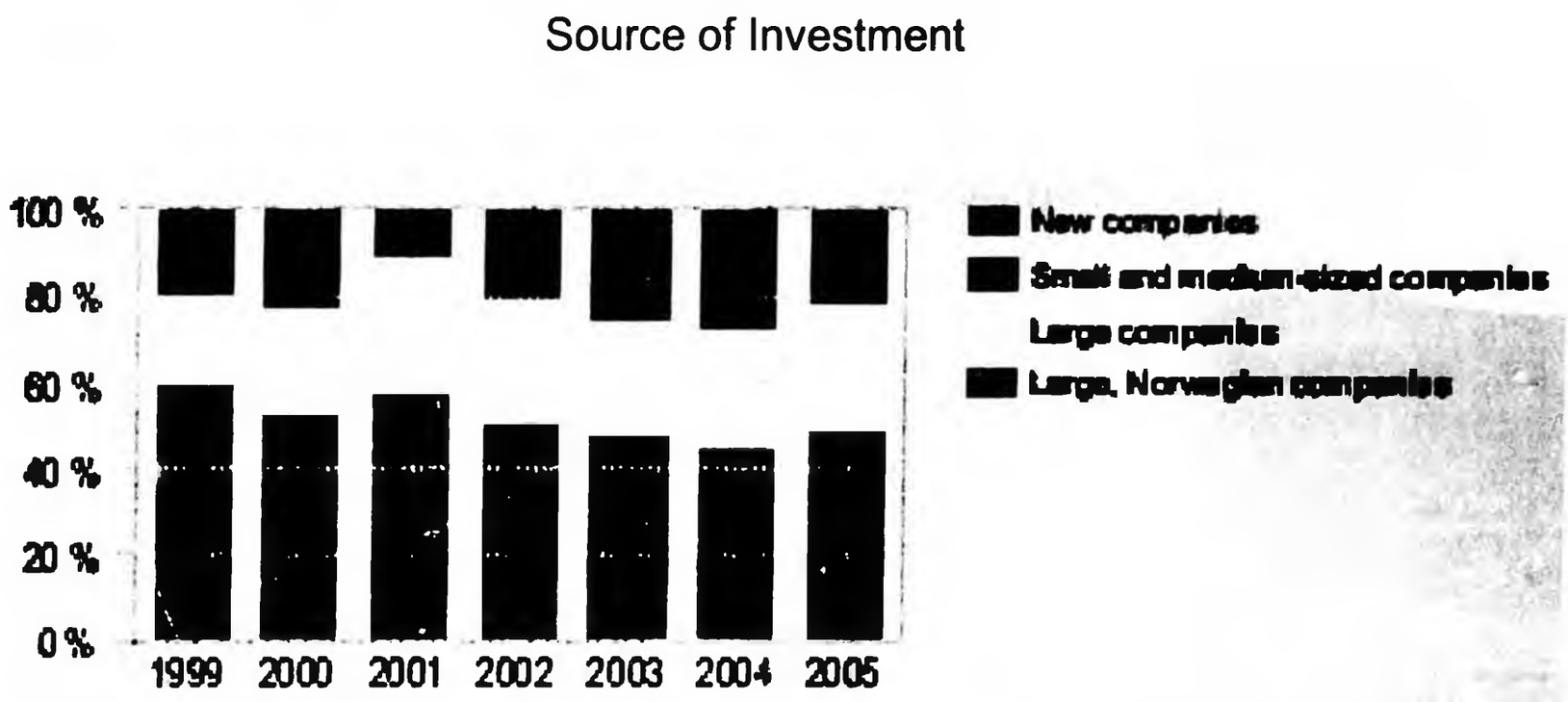


Figure 3.8 Exploration costs in production licences on the Norwegian continental shelf, distributed according to the size of the companies

(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

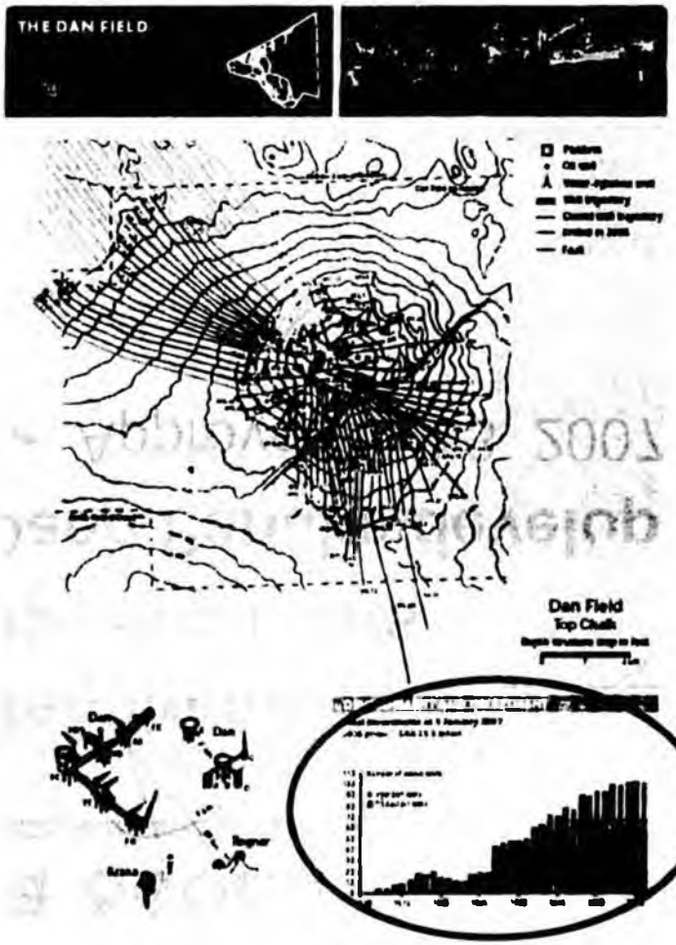
.. and projected

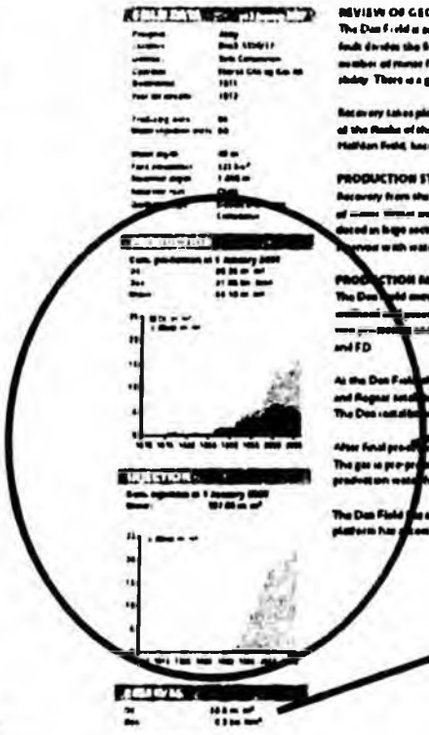
Table 7.5 Estimated investments in development projects, 2007-2011, DKK billion, 2006 prices

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

Denmark

Detail on field-by-field basis





Production and injection history

Reserves and EUR

Total capital investment and development drilling

Nova Scotia Summary

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

Nova Scotia Deep Panuke

Includes sales gas forecast …

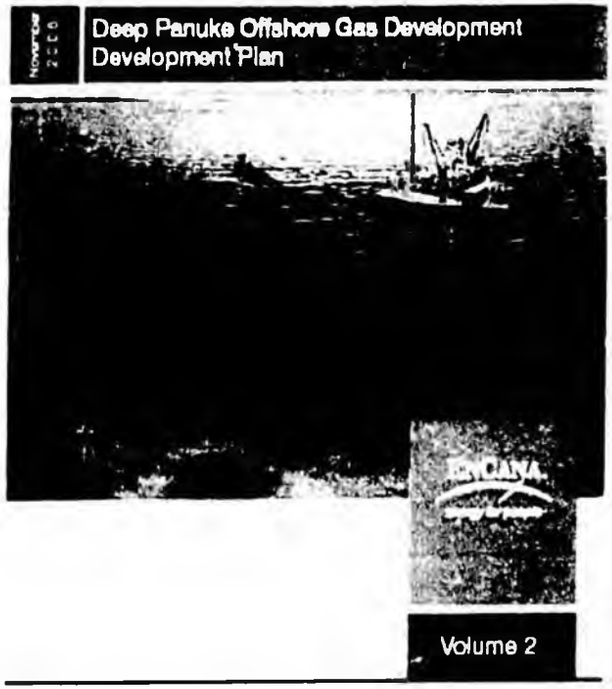
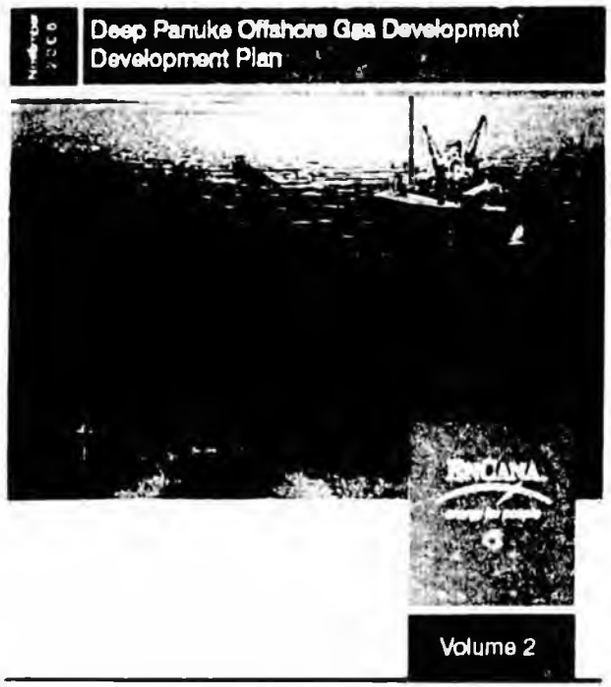


Table 6.1 Sales Gas Forecas

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
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	1.1	45	2.5	90	4.1	145	2.7	97
2018	1.1	40	2.1	76	3.3	118	2.3	81
2019	0.0	0	1.6	58	2.9	103	1.9	67
2020	0.0	0	1.5	52	2.4	86	1.6	55
2021	0.0	0	1.5	52	2.1	73	1.3	47
2022	0.0	0	1.3	45	1.7	62	1.3	45
2023	0.0	0	1.1	40	1.6	55	1.1	41
2024	0.0	0	0.0	0	1.4	50	0.0	0
2025	0.0	0	0.0	0	1.4	51	0.0	0
2026	0.0	0	0.0	0	1.3	47	0.0	0
2027	0.0	0	0.0	0	1.2	41	0.0	0
2028	0.0	0	0.0	0	1.1	38	0.0	0

Nova Scotia Deep Panuke

… and cost forecast by expenditure type



6.3.1 Development Phase Expenditures

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

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

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

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

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

Nova Scotia

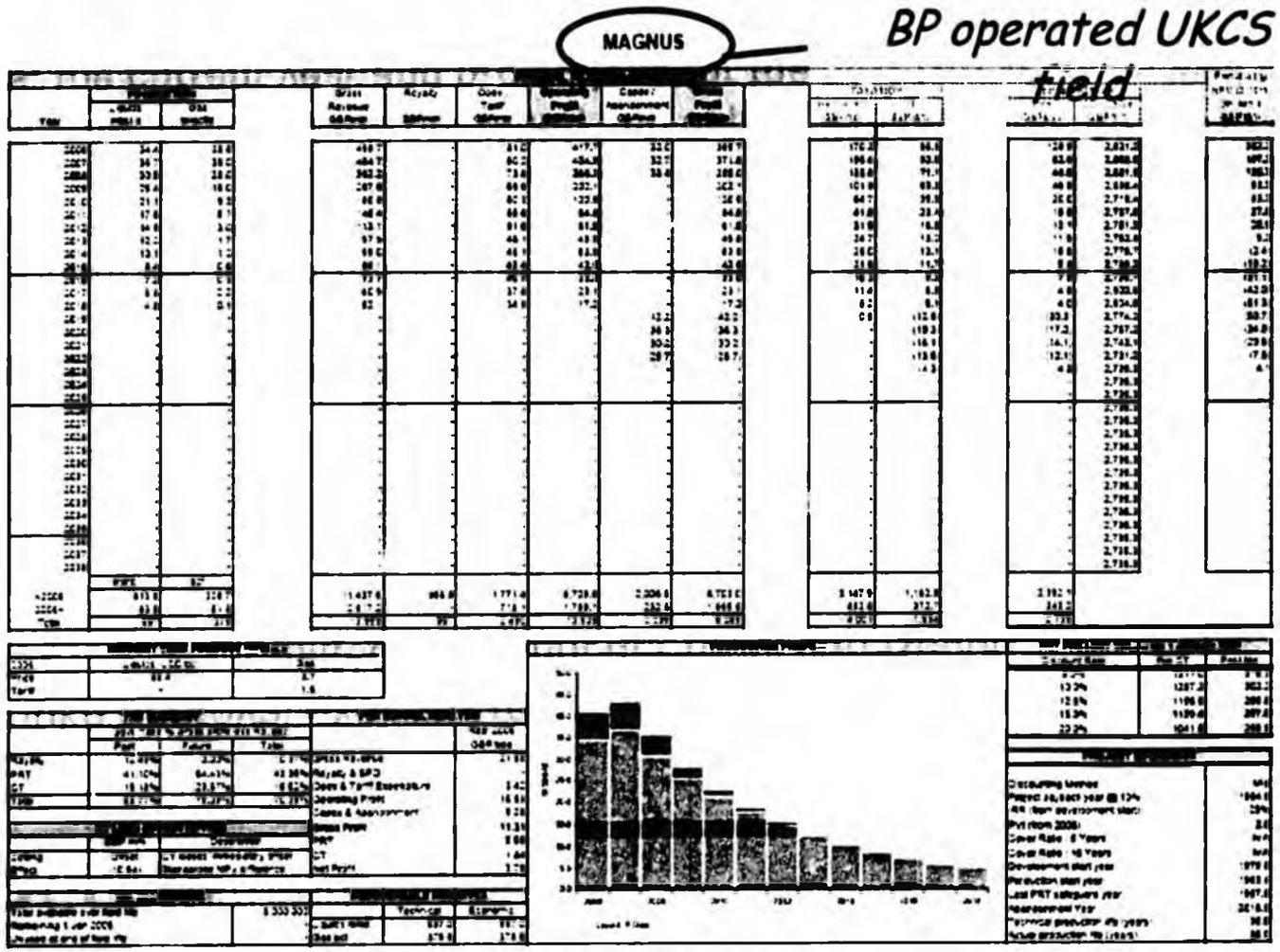
Deep Panuke approval explicitly requires continual update to cost information submitted with Annual Production Report

Condition 30: Submission of Economic Data

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

Publicly Available Sources

Example detailed field cashflow available from Deloitte's subscription service



Source: Deloitte Petroleum Services

Estimated Tax Impacts Under Potential Alternative Scenarios
TIE Sensitivity 1 -- No TIE Credit
FY 2008 - FY 2014

Case	ANS West Coast Price (Real 2008 $/Barrel) $40	$60	$80	$100	$120
(1)	(2)	(3)	(4)	(5)	(6)
Estimated Effective Tax Rate (Percent)					
Current PPT	***4.2%***	***10.7%***	***17.4%***	***23.6%***	***29.3%***
ACES	9.3%	14.6%	20.6%	25.9%	30.8%
Progressivity on Gross: $60 Trigger, 0.225% Increment	6.1%	11.9%	19.0%	25.3%	31.2%
Progressivity on Gross: $55 Trigger, 0.225% Increment	6.1%	12.7%	20.1%	26.4%	32.4%
Progressivity on Gross: $50 Trigger, 0.225% Increment	6.1%	13.7%	21.2%	27.6%	33.5%
Progressivity on Gross: $45 Trigger, 0.225% Increment	6.1%	14.8%	22.3%	28.7%	34.6%
Progressivity on Gross: $40 Trigger, 0.225% Increment	6.2%	16.0%	23.5%	29.8%	35.7%
Progressivity on Gross: $60 Trigger, 0.25% Increment	6.1%	12.0%	19.5%	26.4%	32.8%
Progressivity on Gross: $55 Trigger, 0.25% Increment	6.1%	12.8%	20.7%	27.6%	34.1%
Progressivity on Gross: $50 Trigger, 0.25% Increment	6.1%	13.9%	22.0%	28.9%	35.3%
Progressivity on Gross: $45 Trigger, 0.25% Increment	6.1%	15.2%	23.2%	30.1%	36.6%
Progressivity on Gross: $40 Trigger, 0.25% Increment	6.2%	16.4%	24.5%	31.4%	37.8%
Estimated Annual Average Tax Difference Above Current PPT (Million Dollars)					
ACES	$459	$549	$627	$590	$455
Progressivity on Gross: $60 Trigger, 0.225% Increment	$171	$175	$298	$428	$550
Progressivity on Gross: $55 Trigger, 0.225% Increment	$171	$278	$513	$701	$881
Progressivity on Gross: $50 Trigger, 0.225% Increment	$171	$424	$728	$973	$1,211
Progressivity on Gross: $45 Trigger, 0.225% Increment	$171	$582	$943	$1,246	$1,541
Progressivity on Gross: $40 Trigger, 0.225% Increment	$174	$739	$1,159	$1,519	$1,871
Progressivity on Gross: $60 Trigger, 0.25% Increment	$171	$179	$398	$686	$1,024
Progressivity on Gross: $55 Trigger, 0.25% Increment	$171	$294	$637	$989	$1,391
Progressivity on Gross: $50 Trigger, 0.25% Increment	$171	$456	$876	$1,292	$1,758
Progressivity on Gross: $45 Trigger, 0.25% Increment	$171	$631	$1,116	$1,595	$2,125
Progressivity on Gross: $40 Trigger, 0.25% Increment	$174	$806	$1,355	$1,898	$2,492

Note: Alternatives shown here move progressivity from a "net" to a "gross" wellhead basis and eliminate all TIE credits. Estimates use volumes, aggregate costs and other assumptions underlying DOR's fiscal note to HB2001.

STATE OF ALASKA

SARAH PALIN, GOVERNOR

DEPARTMENT OF TRANSPORTATION AND PUBLIC FACILITIES

OFFICE OF THE COMMISSIONER

3132 CHANNEL DRIVE
PO Box 112500
JUNEAU, ALASKA 99811-2500
FAX: (907) 586-8365
PHONE: (907) 465-3900

November 2, 2007

Ms. Marcia Davis
Deputy Commissioner
Department of Revenue
P.O. Box 110400
Juneau, AK 99811-0400

Dear ~~Ms. Davis,~~ Marcia

I am writing to recap recent email conversations between the Department of Revenue and the Department of Transportation & Public Facilities (DOT&PF) regarding the Dalton Highway (Haul Road). There were a number of questions your Department had for DOT&PF and I have outlined them below.

You have requested information regarding increased maintenance costs on the Dalton Highway as a result of increased truck traffic. You mentioned the operator contends that if the Kuparuk Crude Oil Topping Plant is not modified to produce extra ultra low sulfur diesel, the operator intends to provide the necessary diesel for slope activities by having it trucked from Fairbanks to Kuparuk. The operator estimates that the increased use of the Dalton Hwy (Haul Road) will be an additional 20 truck trips each day. I will assume this to be one-way trips.

If a deduction is not allowed for a crude oil topping plant on the North Slope, low-sulfur diesel may need to be trucked up the haul road from either Anchorage or Fairbanks. This is estimated to require roughly 20 trucks (or 3000bls) daily. What impact is this likely to have on haul road maintenance costs?

After years (decades) of marginal maintenance, over the past 4 years we have increased both our operating and capital efforts significantly. An increase of daily truck traffic on the Dalton of 50-70 trips will not result in any significant (<$1.5 million) additional maintenance effort or cost. We do not expect the cost range to increase significantly until the daily truck traffic increases by 150 trucks (one way) a day.

Where are the maintenance stations located, and how long has DOT been supplying them via tanker?

We have 7 maintenance stations on the Dalton Highway, starting at Livengood at the end of the Steese Hwy and moving north.

- Livengood
- Seven Mile
- Jim River
- Coldfoot
- Chandalar
- Sag River
- Deadhorse (Hwy station, airport and ARRF)

The stations (with the exception of Deadhorse to Sag) are located approximately 60 miles apart - that is the optimum distance for a road maintenance station. These stations are manned 24 hours a day, seven days a week, with the crews working seven days on and seven days off - crew members live predominantly in the Fairbanks area. To the best of my knowledge, DOT&PF has always supplied our remote maintenance stations by tanker. We bid fuel supply contracts with prices FOB each maintenance station.

I understand that fuel produced on the Slope is for the industrial uses there, and only there (although they do sell fuel to the villagers of Nuiqsut), and has no motor fuel taxes applied.

What impact will the increased haul-road traffic have on safety?

We do NOT allow double tankers on the Dalton Highway (capacity approximately 12,000 gallons) only single tankers (capacity approximately 9,000 gallons). Most fuel consumed on the slope is produced on the slope. We supply our seven maintenance stations on the Dalton out of Fairbanks via tanker with no history of mishap.

Do you know the average amount of fuel that DOT trucks up daily or how often the fuel runs happen?

We do not truck daily, but receive a delivery from private vendors on a "keep full" basis and store it in our tanks. The fuel trucks are approximately 9,000 gallons

capacity each. During the course of a year, they make approximately 30 trips to all our stations along the Dalton and deliver approximately 45,000 gallons of gasoline and 300,000 gallons of diesel fuel and heating oil

I hope you find this information helpful. Please don't hesitate to contact me if you need additional information or clarification.

Sincerely,

John MacKinnon
Deputy Commissioner

cc: Ian Laing, Department of Revenue

Topping Plant

Sharon Long

From: Knudson, Kip C. [KKnudson@tsocorp.com]
Sent: Wednesday, November 07, 2007 2:46 PM
To: Sharon Long
Cc: Riley, Dan T.; Hansen, Stephen W

Sharon, hope this helps. Please call me at 907/382-0219 if you have questions.

EPA mandated the sale of ultra low sulfur diesel (ULSD – 15 parts per million sulfur content) in "urban" Alaska on June 2006. "Urban" was roughly defined as communities on the National Highway System. Sale of low sulfur diesel (500 parts per million sulfur content) was mandated in June 2007 for "urban" non-road, locomotive and marine (NRLM) uses. All diesel powered vehicles starting with model year 2007 require the use of ULSD.

Prudhoe was defined as "rural" in EPA rulemaking, but the North Slope operators signed an agreement with DEC/EPA to convert all operations (mobile and stationary) to ULSD by January 1, 2008. The following statement was written by Clint Farr, Clean Air Program at DEC:
"The original agreement between DEC and the North Slope oil producers was for the producers to refine ULSD by December 31, 2007, and then use it in all diesel burning sources. The original agreement was signed in June 2005. The first delay resulted in an amendment shifting the production date to December 31, 2008 and requiring a diesel retrofit project to capture emissions benefits commensurate with emissions gains not realized due to the delay. The amendment was signed in November of 2006. This amended agreement currently still stands."
Rural Alaska and "urban" NRLM will begin the transition to ULSD in June 2010.
Tesoro Alaska began commercial production of ultra low sulfur diesel #1 (ULSD) in May of 2006. In May of 2007 Tesoro began production of ULSD #2 in a dedicated de-sulfurization unit. To date Tesoro has invested over $64 million in unit construction and distribution system changes to manufacture and distribute up to 10,000 barrels per day of ULSD. The de-sulfurization unit can be expanded should demand exceed 10,000 barrels. Total statewide demand is not expected to exceed 10,000 barrels for several years.

Flint Hills Resources entered into a long-term ULSD supply contract with Tesoro in 2006. Tesoro is currently the only in-state manufacturer of ULSD.

Either Flint Hills or Tesoro could supply North Slope demand for ULSD.

Tesoro has not been eligible for any tax breaks for the $64 million investment made to supply ULSD to Alaska.

Topping Plant

Sharon Long

From: Deborah Grundmann
Sent: Wednesday, November 07, 2007 10:18 AM
To: Sharon Long
Subject: FW: Topping plant

FYI
Deb

-----Original Message-----
From: Sen. Charlie Huggins
Sent: Wednesday, November 07, 2007 10:17 AM
To: Deborah Grundmann
Subject: FW: Topping plant

For CH

Jes

-----Original Message-----
From: Galvin, Patrick S (DOR) [mailto:patrick.galvin@alaska.gov]
Sent: Tuesday, November 06, 2007 10:35 PM
To: Dermot Cole; Sen. Charlie Huggins
Subject: RE: Topping plant

Dermot,

I agree. I'm also concerned about the prospect of the state subsidizing the building of a private refinery to compete with another private refinery already operating in the state. The idea doesn't seem to promote fair private competition.

-Pat

-----Original Message-----
From: Dermot Cole [mailto:cole@newsminer.com]
Sent: Tuesday, November 06, 2007 8:19 PM
To: Sen.Charlie.Huggins@legis.state.ak.us
Cc: Galvin, Patrick S (DOR)
Subject: Topping plant

Sen. Huggins, Commissioner Galvin:
The decision on whether or not to build a topping plant is one that private industry should make.
By not granting a subsidy to the companies, that does not mean that the state is forcing the industry to haul fuel up from Kenai.
I don't see why the state should subsidize this to the tune of $150 million, which I think is the figure cited by the commissioner.
For the state to "participate," there should be some justification.
What is it?

Thanks,
Dermot Cole
Fairbanks News-Miner

Roger D. (Dale) Summerlin
Vice President
Health, Safety & Environment

P.O. Box 100360
Anchorage, AK 99510-0360
Phone 907.263.4662
Fax 907.263.4438

ConocoPhillips
Alaska, Inc.

October 4, 2007

Mr. Tom Chapple, Director
Alaska Department of Environmental Conservation
Division of Air Quality
555 Cordova Street
Anchorage, Alaska 99501-2617

Dear Mr. Chapple:

Please find below a summary of the 'North Slope Ultra Low Sulfur Diesel Transition Agreement' progress meeting between representatives from ConocoPhillips Alaska, BP Alaska and the Alaska Department of Environmental Conservation held at ConocoPhillips' Anchorage office on September 27, 2007. Per the agreement, ConocoPhillips is to provide a progress report to your office in March and September of each year through 2008 to keep the Alaska DEC up to date on the status of the ULSD project. As agreed during the September 27 discussion, the meeting satisfied the requirement for the September 2007 progress update. Also noted in the meeting, M.. Batch was to provide you an update on BP's ULSD storage and distribution progress separately. The attached documents included in this transmittal are the handout materials provided at the meeting and a block flow diagram, both current and future, for storage and distribution at Kuparuk.

The ULSD st rage and distribution facility project at Kuparuk is on schedule and on track to be put into operation in December 2008.

The ULSD hydrotreater engineering is very well advanced and is on hold pending the outcome of the AFE approval. The AFE approval process began in September 2007, and once the AFE is approved the project can be quickly restarted. However, the recent exclusion of the tax credit/deduction for topping plants in the proposed tax legislation intended to replace the Alaska Petroleum Profits Tax makes the ULSD hydrotreater project uneconomical as compared to an importing alternative. Until ConocoPhillips fully understands how the State intends to treat this project from a fiscal perspective, they will not be able to determine if installing the hydrotreater is the optimum solution to meet their North Slope ULSD needs and hence unable to approve the AFE. If the AFE is not approved by the end of the year, then it will not be possible to make the 2009 sealift window and the hydrotreater project will be delayed another year. ConocoPhillips agreed to get back in touch with the Alaska DEC in early November to provide an interim progress report.

Planning and logistics are in progress to have ULSD hauled to the Slope beginning January 1, 2009. Commercial arrangements with suppliers have not been n. ide to date, however discussions

are underway. One concern raised was the lack of haul capacity. We do not believe there are adequate tanker trucks available to haul an estimated minimum of ten (10) truck loads of diesel daily. This will require an estimated minimum of 30 tanker trucks. New trucks will need to be built.

The three (3) ConocoPhillips emission reduction projects estimated at $900,000 were discussed. A meeting will be scheduled in late October to discuss further emission reduction projects.

ConocoPhillips representatives again expressed their concern that the proposed tax legislation as written is counter productive for the environment as it does not encourage the development of facilities on the North Slope to reduce emissions.

Additionally, the transport of ULSD from southern Alaska to the North Slope generates an increased risk of hydrocarbon spills. The use of rail car and trucking transport to move/load/discharge ULSD across six boroughs (including a minimum of ten trucks daily on the Dalton Highway) contributes to this spill risk. It is ConocoPhillips' desire, and we believe it is the Alaska DEC's desire, to make ULSD on the Slope and eliminate hauling/importing ULSD.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Dale Summerlin

Roger D. (Dale) Summerlin

cc: Mr. Bob Batch - BP
Commissioner Larry Hartig – ADEC
Mr. Georg Storaker – CPAI

CS Retains

- **Administrative tools to administer PPT and forecast more accurately**
- **Exempt auditors** cs 9
- **Information gathering including more freq. filings**
- **Information sharing DOR to DNR and DNR to DOR each maintaining the other's confidentiality requirements**
- **Modified TIE credits (CS Sec. 13)**
- **1000.00/ day penalty for failure to file (CS 14 gove sec 47)**
- **Must file whether or not tax is due (CS14**
- **Explorer/producer not producing must file (cs16 gov. 48)**
- **Powers of DOR (cs 17 gov 49)**
- **Electronic Filing (cs 18 gov 51)**
- **Lease expends ARE (cs 19 gov 56)**
- **Direct cost (cs 20 gov 57)**
- **Expendituress ARE NOT (cs 21 gov 58 DRR ,Corrosion –"SB80", Topping Plant)**

Constitutional & privacy issues need to be look @ re Disclosure of tax info

NOT IN CS

Tax rate
Progressivity trigger loweded to $30
Alternative Minimum Tax (10% gross floor)
Spreading Credits over 2 years
Statute of Limitations extension
Tax credit fund
Changing tax calculation periods
Slew of language corrections and conformity issues throughout bill
Constitutional & privacy issues need to be look @ re Disclosure of tax info
Treatment capital and operating credits and carry forwards
Treatment of tax exempt entities & transferable certificates
DNR Commissioner authority re tax credit eligibility
Ring Fencing

TIE Credit Comparison PPT vs CSSB2001(RES)

	Capital Spend in millions	CSSB 2001(RES))	
2001 April 1-Dec 31	$1,207,000,000.00		
2002	$1,296,700,000.00		
2003	$1,186,800,000.00		
2004	$1,136,900,000.00		
2005	$1,268,000,000.00		
January 1 - March 31, 2006 (est)	$416,325,000.00		
	$6,511,725,000.00	$600,000,000.00	Difference
Amount of eligible credit	$1,302,346,000.00	$120,000,000.00	$1,182,346,000.00

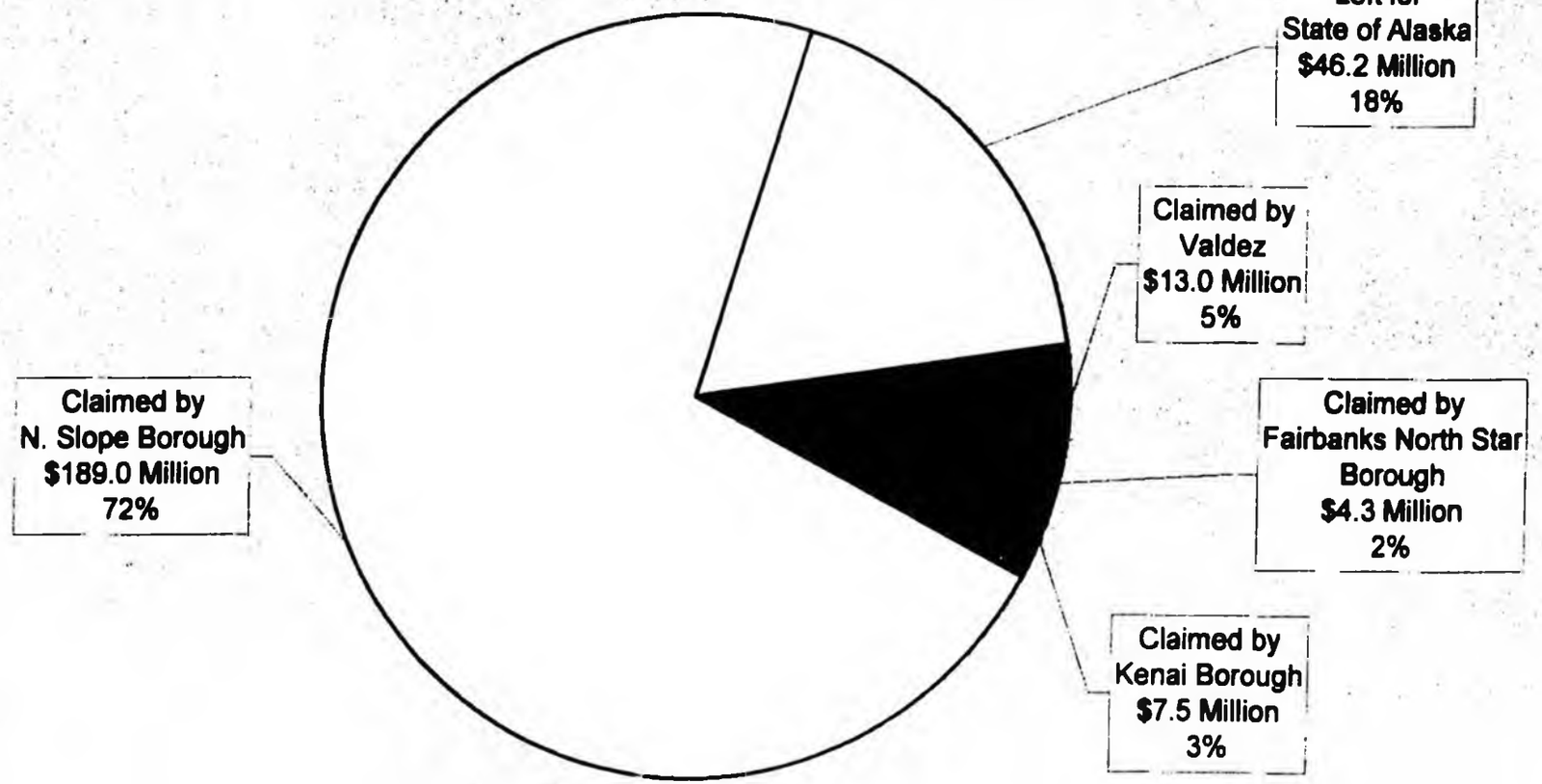
Year	TIE estimate at $60 ANS west coast	PPT Amount of Credit Remaining		CSSB2001(RES) 10% of Nonproducer capital spend from 3/31/06 to 1/1/08[1]
2007	$181,700,000.00	$1,120,646,000.00	$181,700,000.00	$120,000,000.00
2008	$213,700,000.00	$906,946,000.00		
2009	$188,100,000.00	$718,846,000.00		
2010	$197,500,000.00	$521,346,000.00		
2011	$190,200,000.00	$331,146,000.00		
2012	$198,000,000.00	$133,146,000.00		
2013	$133,146,000.00	$0.00		
Total	$1,302,346,000.00		$301,700,000.00	Difference $1,000,646,000.00

[1]The amount of eligible credit is 10% of the amount actually expended by a non-producer from 3/31/06 to 1/1/08

In order to claim a credit of $120,000,000 a non-producer would have to spend $1,200,000,000 from 3/31/06 to 1/1/08

PPT plus out 1.3 B
NCES $ 181 M
SKES

2005 State 20-Mill Levy
Oil & Gas Property Tax GF Revenue
(AS 43.56 - 20-Mill Advalorem Tax)



Five municipalities claimed less than 1%

Total - $260.9 Million

The state levies a 20-mill tax against oil and gas property. A municipality that has O and G property located within its borders may also levy a tax on those properties. This local tax amount is subtracted from the total of the state's 20-mill tax.

by G. Wilkowski Office

All posted on LB&A website

LB&A Handout
Pedro v Meyers

1 HR presentation

Ak Gas – uneconomic unless we liquify it

Proposed revisions to the PPT

October 18, 2007

Presentation to

The Alaska Legislature

Overall Recommendation

I would strongly recommend **not** to make any changes in the PPT law, other than the transparency provisions.

Changing taxes substantially every year creates an image of serious fiscal instability that could damage investor confidence in Alaska.

Overall Recommendation

The current law already provides for a review mechanism by 2011.

will have
- a couple aud
would know
it was work

The year 2011 is the appropriate time to make such revisions because at that time the first audits will have been completed and final and reliable information would be available.

Current System

Table 5.26. WEST SAK

Undiscounted Government Take (Income only)

WTI US $	WTI Can $	Gas Price Can $	Heavy oil price Can $	COST-7	COST-6	COST-5	COST-4	COST-3	COST-2	COST-1
20	22.73	$1.89	$14.35							60.38%
30	34.09	$2.84	$24.32			60.22%	59.56%	59.31%	59.27%	59.19%
40	45.45	$3.79	$34.28	59.68%	59.60%	59.54%	59.49%	59.45%	59.21%	59.09%
50	56.82	$4.73	$44.25	59.81%	59.81%	59.83%	59.72%	59.62%	59.66%	59.77%
60	68.18	$5.68	$54.22	60.66%	60.66%	60.64%	60.69%	60.83%	60.98%	61.09%
70	79.55	$6.63	$64.18	61.83%	61.87%	62.02%	62.18%	62.34%	62.45%	62.53%
80	90.91	$7.58	$74.15	63.24%	63.39%	63.53%	63.68%	63.80%	63.88%	64.02%
90	102.27	$8.52	$84.11	64.74%	64.88%	65.02%	65.15%	65.24%	65.36%	65.53%
100	113.64	$9.47	$94.08	66.21%	66.35%	66.50%	66.59%	66.70%	66.86%	67.04%