ALASKA LEGISLATURE COMMITTEE FILES 1987-1988 8672
4950 HRES HB 164 (FILE 3) (see ELF) 522

1 INTRODUCTION

Within UK designated areas, mainly in the North Sea, lie some of the largest oil and gas fields found on the continental shelf. The United Kingdom also has a number of onshore fields but they are all relatively small.

Ownership of oil or gas in place, whether onshore or offshore, rests with the State and the Government has the power to award licences which permit exploration or development in the areas covered.

For offshore areas there are two kinds of licence:

(1) The exploration licence – is a non-exclusive licence and entitles the holder to conduct preliminary exploration activities in any area apart from one covered by a production licence.

(2) The production licence – entitles the holder to explore, appraise and develop, subject to consent from the Department of Energy (DoE) any field in the specified area.

Production licences are awarded for defined areas which have been offered, either under cash tender or for a fixed price, under successive licensing rounds. To date there have been ten separate licensing rounds.

The onshore licensing system is broadly similar but exploration licences are awarded for specific areas and are now awarded under the licensing round procedure.

2 FISCAL REGIME – CORPORATE

The Government 'take' from oil and gas revenues comprises the following elements:

(1) Government royalties

(2) Petroleum revenue tax

(3) Corporation tax

A special office, the Oil Taxation Office (OTO), deals with the tax affairs of oil companies and royalties are dealt with by the DoE.

(1) Government Royalties

Offshore fields, other than those in the Southern Basin of the North Sea, for which the DoE made the decision to allow development on or after 1 April 1982 are exempt from Government royalty.

For non exempt offshore fields the precise royalty calculation is determined by the round in which the licence was issued. For fifth and later round licences royalty is 12.5% of the landed value of production. For fourth and earlier round licences deductions are allowed for conveying and treating costs, thus making the well head the point of valuation.

The Government takes some of its royalty entitlement in kind and in these cases if a fourth or earlier round licence is involved it pays amounts to the oil company to cover the conveying and treating costs of the oil taken in kind.

For onshore licences issued since 1982 the royalty rate is normally flat 12.5% but under earlier licences royalty is charged on a graduated basis with 12.5% as the highest rate.

(2) Petroleum Revenue Tax (PRT)

PRT, now charged at 75%, is assessed on profits from oil won under the authority of a licence on a 'field by field' basis, ie the taxable unit is the particular oil or gas field whose co-ordinates are determined by the DoE on geological characteristics. In general losses relating to one field cannot be set against profits of other fields. Although PRT applies to both onshore and offshore fields, onshore fields are generally unlikely to pay PRT because of their size and production rates.

PRT is assessed, for 6 monthly chargeable periods, at 75% on net profit less "oil allowance" subject to a possible reduction under an alternative calculation ("safeguard").

The net profit for PRT purposes is the sum of the positive amounts less the sum of the negative amounts.

The major items included as positive amounts are:

Proceeds from arm's length sales of oil (Note a)
Market value of non-arm's length disposals of oil (Note a)
Market value of oil appropriated to refining
The excess of market value over nominated proceeds (Note b)
One half the market value of oil in "stock" at the end of the period (reversed in the next period)
Tariff receipts net of any tariff receipts allowance (Note c)
Disposal receipts
Conveying and treating receipts.

The major items included as negative amounts are:

Royalty payable (including annual licence rentals)
Field expenditure (Note d)
"Uplift" (Note e)
Exploration and appraisal expenditure
Research and development expenditure
Cross-field expenditure allowed by the OTO
Abortive exploration expenditure
Unrelieved field losses
Any net loss from the preceding period.

The following points are relevant:

(a) Oil sales are at arm's length only if certain conditions are met. It is not sufficient for sales merely to be to an unconnected party.

If the arm's length conditions are not met market value is substituted for sales proceeds, market value now being determined by reference to an evidential base of comparable arm's length sales.

(b) To prevent the oil companies manipulating which oil sales are subject to PRT a nominations system has been introduced. If arm's length sales are not correctly nominated an adjustment is now made to replace sales proceeds with market value.

(c) Tariff receipts – field assets, such as pipelines and terminals, may be used by other, usually newer fields. This generates tariff receipts, usually calculated on the basis of throughput of oil, which are subject to PRT in the hands of the recipient. A quantity allowance is granted as a deduction for each period, the tariff receipts allowance.

(d) Allowable expenditure – expenditure deducted against an assessment is generally that agreed and determined by the OTO since the previous assessment, rather than that expenditure incurred in the period.

Field expenditure must fall under certain prescribed headings, which cover exploration costs through to selling costs but PRT does not extend to "downstream" operations.

Certain expenditure is specifically disallowed, in particular interest, the cost of acquiring land and with certain exceptions the cost of a building or structure on land.

Long-term assets, ie assets having a useful life extending beyond the period covered by the expenditure claim, are subject to certain special rules. Full front-end relief is granted for most long term assets, the exception being long-term assets which are mobile and not dedicated to any particular field. Relief for expenditure on such assets is spread over the life of the asset and allocated to the vari fields on which the asset is successively used.

(e) Uplift – a special allowance intended to compensate for the lack of an interest deduction. Uplift is currently granted at 35 per cent of qualifying expenditure, broadly initial appraisal and development expenditure.

Uplift is not available on expenditure incurred after the field has reached a break-even point. There are detailed rules to calculate when "payback" occurs.

(f) The fourth to eighth items of the negative amounts above are the areas where the field concept has been breached. They are fairly restricted but have been gradually expanded to encourage exploration and development.

(g) Oil allowance – is the cash equivalent of a quantity of oil. It is used only if a net profit exists for a particular period and is granted until overall maximum quantity has been used.

For offshore fields, other than Southern Basin fields, for which development consent was given on or after 1 April 1982, the oil allowance is 500,000 metric tonnes for each chargeable period w a maximum aggregate quantity of 10 million metric tonnes. For oil fields these quantities are halved.

(h) Safeguard – is an alternative calculation of PRT, intended to guarantee a minimum return from the field. It is only available for a fixed number of chargeable periods in the early years of a field's l The number of periods for which safeguard is available is 1½ time the number of chargeable periods in the "payback period".

Administration

PRT is payable for 6 monthly chargeable periods ending June an December. Returns of income and an estimated PRT calculation a due two months after the end of the period and the tax calculated payable, net of any previous stage payments, is then due.

An assessment is due within five months of the end of the period and any balance of tax is due by the end of the sixth month. It should be noted however that interest runs from the end of the second month in any event (also on any repayment due).

Additionally 6 stage payments are required, each one equal to one-eighth of the calculated (not assessed) liability for the previous period. These are due monthly commencing at the end of the second month in the period.

ration Tax

Companies engaged in oil or gas exploitation are subject like other companies to UK corporation tax on their trading profits but the following special rules apply.

The ring fence – UK oil and gas extraction activities are treated as a separate trade from other trading activities ...ed on by the company. The profits from this separate trade – 'the ring fence trade' – may not be reduced by losses from other activities. On the other hand losses from the ring fence trade may be used to reduce profits from non-ring fence activities.

Where a company has both ring fence and non-ring fence activities loan interest can only be deducted from ring fence profits to the extent that the loan was used to meet expenditure relating to the ring fence trade. Interest allowed on loans from an associated company is restricted to a reasonable commercial rate, and the OTO are contending that "thin capitalisation" rules apply.

There are also restrictions, in some circumstances, on the use of advance corporation tax by an exploration and production company.

Sales values – if market value is used for PRT purposes those same values are normally substituted for actual sales proceeds in the corporation tax computation.

Capital allowances – items of plant and machinery such as drilling rigs, production platforms, pipe-lines etc, qualify for a 25 per cent writing down allowance each year calculated on the reducing balance basis.

Exploration and appraisal expenditure qualifies for scientific research allowances which give immediate relief for 100% of the cost to a company which is carrying on a 'related trade'. If the company does not have such a trade the relief will only become available if such a trade is set up and commenced. It is accepted by the OTO that a development decision constitutes commencement to trade.

Intangible development drilling costs (with the possible exception of the first development well) can be deducted as revenue expenditure under what is known as the New Brunswick rule. The OTO now argues that expenditure on the first development well of a particular field only qualifies for mineral extraction allowances. These are writing down allowances which are available at two levels, 10% pa for acquisition of a mineral asset and 25% pa for winning access and certain other qualifying expenditure.

(d) Royalty and PRT are deducted in computing taxable profits.

Administration

Corporation tax is normally payble 9 months after the end of the company's accounting period.

3 FISCAL REGIME – INDIVIDUAL

Employees whose duties are performed offshore in the UK sector of the continental shelf are treated under a special provision as working in the United Kingdom. This means that the more favourable treatment of earnings for duties performed outside the United Kingdom which applies in certain circumstances is not available.

4 FISCAL REGIME – OTHER

The UK sector of the continental shelf (outside the 12 mile limit) is not part of the United Kingdom for VAT purposes. It is therefore possible to 'export' various services relating to the offshore installations and so obtain the benefit of 'zero-rating'. The treatment of the supplies normally made in connection with offshore oil and gas activities has been agreed on an industry basis with the Customs and Excise authorities.

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UCTION

The Norwegian sector of the North Sea has several large oil and gas fields currently producing. Because of the potential impact on the economy of such a small nation Norway has pursued a policy of structured development of its oil and gas resources. Each development requires approval of the Storting (parliament), and the State participates in each licence through Statoil (the 100% State owned oil company), whose costs up to 1 January 1987 were carried by the other participant in each venture prior to a find being declared commercial. The State and Statoil are not carried in licences issued after 1 January 1987. Statoil's interest in existing licences is between 50% and 85% and if Statoil is not initially the operator on a licence there are usually provisions enabling Statoil to assume that role at a later date.

EGIME – CORPORATE

Norway has four main levies on oil and gas production.

Production fee (Royalty)

Income Tax

Special Petroleum Tax

Capital Tax

ion fee (Royalty)

Production fee is charged on each licensee under a licence. It is only charged on fields whose development plan was accepted before 1 January 1987.

The rate is a flat 10% on licences issued before 1972 and varies with production for later licences.

The licensee is required to pay a production fee of 8% of the value of the quantity of oil produced. From the time when the quantity of oil produced from one production area reaches the following average quantities over a 30-day period, the production fee is paid at the following rates on the value of the whole quantity:

6,500 Standard cubic metres per day	975b/d	10%
16,000 Standard cubic metres per day	2400b/d	12%
35,000 Standard cubic metres per day	5250 b/d	14%
55,000 Standard cubic metres per day	8250b/d	16%

If the daily average for the first 30 days of production from a production area exceeds the level at which the fee is 8%, the production fee is raised from the day when the production first exceeded the level in question.

If the daily average of production from a production area for which a production fee of more than 12% has been paid should later fall under the relevant limit during a 30-day period, the production fee is reduced correspondingly in accordance with the table from and including this period, but not to less than 12%.

On produced petroleum other than oil, a production fee of 12½% is payable.

Costs of construction and operation of pipelines from the individual production installation to the production area shipment point are deductible when calculating the production fee, if the Ministry regards it as reasonable in view of the distance of transportation and other prevailing circumstances.

When granting an individual production licence or subsequently, the Ministry may stipulate lower production fee rates if the depth of the sea, the capacity per well or other circumstances so indicate.

Valuation of oil is under the "norm price" system in operation in Norway. This price is established for oil for each field in respect of each calendar quarter. It is "equivalent to the price at which petroleum could have been sold between independent parties in a free market". The price is fixed by a board appointed by the Ministry of Energy. However, the production fee for oil is usually paid in kind.

Although the norm price system allows a gas price to be established this has never been done.

(2) Income Tax

Income tax is governed by the General Tax Act of 1911, and is generally split between a municipal tax of 23% and a state tax of 27.8%. These taxes are both paid to the state where offshore operations are concerned.

The major difference is that dividends paid in accordance with the Companies Act 1976 are deductible in computing profits for the state tax but not the municipal tax. The 1976 Companies Act restricts dividends by reference to reserve fund rules.

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All expenses incurred in order to obtain or secure income are tax deductible.

The normal income tax rules are amended in several ways by the Petroleum Tax Act for offshore operations:

income from oil is computed under the "norm price" rules

there are several adjustments to book income, some of them only affecting the timing of a deduction.

(i) Exploration costs may either be expensed currently or deferred and amortised.

Exploration costs include all expenditure incurred prior to an area being declared commercial.

If the costs are capitalised the amortisation period is at the discretion of the taxpayer but amortisation must end within 5 years from the related field coming on stream.

Interest on loans used to finance exploration costs may similarly be expensed immediately or capitalised. The deduction of interest on ... company loans is however subject to thin capitalisation rules.

(ii) Exploitation expenditure must be capitalised and depreciated. The expenditure to be capitalised includes wages of employees in development work and overhead costs.

Offshore production assets are depreciated on a straight line basis over a minimum period of 6 years. The depreciation must be provided in the company's accounts to be allowable for tax purposes.

Depreciation commences when the asset comes into use, but from the year of investment for assets acquired after 1 January 1987.

The normal rules of the General Tax Act apply to onshore assets which are depreciated on a declining basis at rates from 2% to 30%.

For assets acquired before 1 January 1987 depreciation is not available until the particular field under development begins production and accordingly development costs of such a field cannot be offset against taxable income from a currently producing field until the field commences production.

(iii) production costs are expensed as incurred.

(c) There is no restriction on utilisation of losses from operations on the continental shelf against profits from other activities. However, because the special petroleum tax is assessed on the same basis as income tax, it is usually preferable to carry offshore losses forward. There is a maximum 15 year loss carry forward but the Ministry of Finance has power to extend the period.

Losses may be carried backwards for two years if an activity ceases.

Only 50% of losses from activities not carried out on the continental shelf may be set off against profits from continental shelf activities.

(3) Special Petroleum Tax

Introduced by Section 5 of the 1975 Petroleum Tax Act.

Charged at the rate of 30% (25% prior to 1980) on those who produce or transport petroleum through pipelines.

The special tax is assessed on the same basis as income tax with the following exceptions:

(a) no dividend deduction

(b) losses from other activities are not deductible

(c) a special deduction is allowed.

For fields whose development plan was accepted before 1 January 1987 this deduction consists of an uplift comprising an annual deduction of 6⅔% of the uplift base. An asset remains in the uplift base for 15 years, giving total uplift of 100%. An individual asset enters the base in the year following its first depreciation. If a field does not produce for the 15 years required to obtain 100% uplift the uplift rate may be adjusted.

Pipeline uplift may, if the pipeline is owned by a separate company and the uplift exceeds the assessable profit, be allocated amongst the pipeline users to the extent of the excess.

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Prior to 1980 uplift was 10% pa over 15 years.

For fields whose development plan was accepted after 1 January 1987 no uplift can be claimed. Special tax is calculated on the net income that exceeds a "production grant". For 1987 the production grant is set at 15% of the value of produced petroleum (for oil based on norm prices).

...nt and Payment Procedures

Income tax and the special petroleum tax are assessed by a special Assessment Board.

A return of income for the preceding calendar year is submitted to the Oil Taxation Office by 1 April. The Oil Taxation Office makes a recommendation to the Assessment Board. The recommendation is presented to the company for comments. After consideration of the company's comments and any further information requested the Assessment Board raises an assessment in the autumn of the assessment year.

Any appeal must be lodged within 3 weeks, although in practice a preliminary appeal stating the items subject to appeal is accepted. A full appeal is subsequently prepared.

Any court proceedings must be commenced within 6 months of the determination of the appeal.

Payment of the income tax and special petroleum tax is in two instalments, based on a preliminary estimate of income provided to the Oil Taxation Office in August of the year in question. The instalments are payable in October and the following April and are based on a preliminary assessment.

Any balance of tax due or refund is paid after the issue of the final assessment. Interest is payable or receivable as the case may be.

...ment

Norway has decided not to allow tax deductions for abandonment provisions or actual costs but has proposed a system of Government grants, which will not be taxable. The grant will be negotiated on a field by field basis. It is intended that the grant will approximate the level of tax relief that would have been obtained if a deduction for abandonment costs was allowed.

Thin Capitalisation

Interest costs are deductible for both income tax and special petroleum tax but the Oil Taxation Board has laid down rules on both debt/equity ratios and interest rates. The main rule on debt equity ratios is:

(a) Exploration phase – 100% equity required

(b) Development phase – 20% equity required

(c) Production phase – 100% debt allowed.

Further the interest rate must not exceed market rate.

The above restrictions will apply if debt is obtained from an affiliated company or is guaranteed by an affiliated company. The debt/equity restrictions will generally not apply if the borrower (licensee) has other licences that are on-stream, thus generating income sufficient to pay a higher percentage of loan financing.

Research and Development

As a condition of obtaining new licences oil companies have often made payments to Norwegian companies for research and development projects. The tax treatment of these payments has varied. In 1984 it was accepted that such contributions could be expensed immediately for both income tax and special tax purposes. The Government has since decided that the contributions cannot be deducted against offshore income for special tax purposes.

Ekofisk Waterflood Project

In 1983 a special law was passed to improve the economics of this particular and other waterflood projects. The Government accepted that the project was not viable without special incentives and it is expected that this may be a forerunner of future incentives granted on a case by case basis.

(4) Capital Taxes

Capital taxes are paid by Norwegian corporations at 0.3% (1987) of net worth.

Net worth is arrived at by deducting all debt (excluding income tax) from assets. Assets are normally valued at book value. Capitalized exploration costs are excluded. Depreciable assets used in petroleum production or pipeline transportation are valued at book value excluding capitalized interest and exchange losses. Other plant and machinery is usually accepted at book value except onshore real property for which separate tax values exist.

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Oil stocks are valued either at book value (cost of production) or at norm price if they have been transported beyond the norm price point.

3 FISCAL REGIME – INDIVIDUALS

An individual resident or domiciled in Norway is taxed on worldwide income. Non residents are taxed on income from Norwegian sources. This includes earnings from employment in the Norwegian sector of the North Sea.

There are both state and municipal taxes. State taxes are levied at rates up to 34% on net income exceeding NoK 215,000 (NoK 258,000 for individuals with dependents).

Municipal taxes are levied at 22% and not deductible for state tax purposes. Most benefits in kind are taxed.

Social security premiums are charged at 11.4% of gross income from individuals, plus 17.1% from employers.

The tax year follows the calendar year and returns must be submitted by 31 January of the following year.

4 FISCAL REGIME – OTHER

Valued added tax is charged on most goods and services supplied in Norway at 20%. For continental shelf activities the VAT is zero rated.

Customs and Excise duties are payable.

(*a*) two months after the end of the chargeable period for which the assessment was made; or

(*b*) the date on which it was paid,

whichever is the later, until repayment(a)](b).

SCHEDULE 3

Section 1.

PETROLEUM REVENUE TAX: MISCELLANEOUS PROVISIONS

Definition of sale of oil at arm's length

1.—(1) For the purposes of this Part of this Act a sale of any oil is a sale at arm's length if, but only if, the following conditions are satisfied with respect to the contract of sale, that is to say—

(*a*) the contract price is the sole consideration for the sale;

(*b*) the terms of the sale are not affected by any commercial relationship (other than that created by the contract itself) between the seller or any person connected with the seller and the buyer or any person connected with the buyer; and

(*c*) neither the seller nor any person connected with him has, directly or indirectly, any interest in the subsequent resale or disposal of the oil or any product derived therefrom.

(2) Section 533 of the Taxes Act (connected persons) shall apply for the purposes of the preceding sub-paragraph.

Definition of market value of oil

2.—(1) For the purposes of this Part of this Act the market value of any oil shall be ascertained in accordance with this paragraph; and in this paragraph the time as at which market value is to be ascertained is referred to as "the relevant time"(c).

(2) Subject to the following provisions of this paragraph, the market value of any oil at the relevant time is the price at which the oil could have been sold to a willing buyer at that time in a sale at arm's length under a contract of sale made at that time and satisfying the following conditions, that is to say—

(*a*) the contract requires the oil to have been subjected to appropriate initial treatment before delivery;

(*b*) the contract requires the oil to be delivered—

(a) 1980(P) s. 2 *in relation to tax charged for any period ending on or after* 31 *December* 1979. *Originally* "from four months after the end of the chargeable period for which the assessment was made until repayment".

(b) *See* 1982 s. 139(6) *and* Sch. 19 para. 13(5) *in respect of repayments due in respect of the chargeable period ending on* 30 *June* 1983.

(c) *See*—

1982 s. 134 *and* Sch. 18—*alternative valuation of ethane used for petro-chemical purposes.*

1986 s. 109—*alternative valuation of light gases where an election is made under* 1986 s. 109 *and accepted by the Board.*

(i) in the case of oil extracted in the United Kingdom, at the place of extraction; or

(ii) in the case of oil extracted from strata in the sea bed and subsoil of the territorial sea of the United Kingdom or of a designated area, at the place in the United Kingdom at which the seller could reasonably be expected to deliver it or, if there is more than one such place, the one nearest to the place of extraction;

(*c*) in the case of oil whose market value falls to be ascertained as at a particular time for the purposes of paragraph (*b*) of section 2(4) or paragraph (*d*) of section 2(5) of this Act or, subject to sub-paragraph (3) below, under paragraph 3 below for the purposes of paragraph (*b*) or (*c*) of the said section 2(5), the contract is for the sale of the whole quantity of oil whose market value falls to be ascertained as at that time for the purposes of the paragraph in question, and of no other oil [and, for the avoidance of doubt, it is hereby declared that the terms as to payment which are to be implied in the contract shall be those which are customarily contained in contracts for the sale at arm's length of oil of the kind in question(a)].

(3) If oil whose market value falls to be ascertained as at a particular time under paragraph 3 below for the purposes of paragraph (*b*) of the said section 2(5) was not all disposed of to the same person, then the market value at that time of so much of that oil as was disposed of to any one person shall be ascertained in accordance with sub-paragraphs (1) and (2) above as if that were the only oil whose market value fell to be ascertained as at that time for those purposes (with sub-paragraph (2)(*b*) above applying accordingly).

[(3A) Where all or any of the oil whose market value falls to be ascertained in accordance with sub-paragraphs (1) and (2) above has been subjected to initial treatment before being disposed of or relevantly appropriated, the appropriate initial treatment referred to in sub-paragraph (2)(*a*) above shall, as respects that oil, include the whole of that treatment(b).]

(4) The provisions of sub-paragraphs (2) and (3) above shall apply for the ascertainment of the market value of oil in any case mentioned in paragraph 2(2) of Schedule 2 to this Act as they apply in relation to the corresponding case mentioned in those provisions.

[2A.—(1) Paragraph 2 above shall have effect in accordance with this paragraph where the oil whose market value falls to be ascertained at

(a) 1983 s. 38.

(b) 1980 s. 109(6) *in relation to chargeable periods ending after 31 December 1979.*

any time in accordance with sub-paragraphs (1) and (2) of that paragraph, or in accordance with those sub-paragraphs as modified by sub-paragraph (3) of that paragraph, consists of or includes gas(a).

(2) Sub-paragraph (2)(*a*) of paragraph 2 above shall not apply to so much of the oil as consists of gas unless—

(*a*) it has been subjected to initial treatment before being disposed of or relevantly appropriated; or

(*b*) it has, after being disposed of or relevantly appropriated, been subjected to initial treatment by or on behalf of the participator in question or by or on behalf of a person who is connected with him within the meaning of section 533 of the Taxes Act;

and where oil consisting of gas has, whether before or after being disposed of or relevantly appropriated, been subjected to initial treatment by or on behalf of the participator in question or by or on behalf of a person who is connected with him as aforesaid the appropriate initial treatment referred to in sub-paragraph (2)(*a*) of paragraph 2 above shall include the treatment to which it has been so subjected.

(3) Where the initial treatment mentioned in sub-paragraph (2) above includes treatment in order to separate gas of one or more kinds which are transported and sold in normal commercial practice, the market value of the gas of each such kind which is separated shall be ascertained in accordance with sub-paragraphs (1) and (2) of paragraph 2 as if that were the only oil whose market value fell to be ascertained at the time in question (with sub-paragraphs (2)(*b*) of paragraph 2 applying accordingly).

(4) Where the oil consists of or includes natural gas within the meaning of the Energy Act 1976, it shall be assumed for the purposes of paragraph 2— 1976 c.76.

[(*a*) that any authorisation granted under section 7 or 8 of the Gas Act 1986 for the supply of the gas under the contract mentioned in sub-paragraph (2) of that paragraph; and 1986 c.44.

(*b*) that no authorisation is required under those sections for the supply of the gas under that contract if no such

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(a) *See—*

1982 s. 134 *and* Sch. 18—*alternative valuation of ethane used for petro-chemical purposes.*

1986 s. 109—*alternative valuation of light gases where an election is made under* 1986 s. 109 *and accepted by the Board.*

authorisation is required for the supply of the gas (a)](b).]

Aggregate market value of oil for purposes of section 2(5)

3.—(1) For the purposes of subsection (5) of section 2 of this Act the aggregate market value of any oil falling within paragraph (*b*) or (*c*) of that subsection shall be arrived at by ascertaining, for each calendar month in the chargeable period in question, the market value at the material time of so much, if any, of that oil as was—

(*a*) in the case of oil falling within the said paragraph (*b*), delivered as there mentioned in that month;

(*b*) in the case of oil falling within the said paragraph (*c*), appropriated as there mentioned in that month,

and, in either case, aggregating the market values so ascertained(c).

(2) In this paragraph and elsewhere in this Part of this Act "calendar month" (where those words are used) means a month of the calendar year, and "the material time", in relation to a calendar month, means noon on the relevant day, that is to say—

(*a*) for a month containing an odd number of days, the middle day of the month;

(*b*) for a month containing an even number of days, the last day of the first half of the month.

Oil delivered in place of royalties to be disregarded for certain purposes

1934 c.36.

4. Oil delivered to the Secretary of State under the terms of a licence granted under the Petroleum (Production) Act 1934 shall be disregarded for the purposes of section 2(5) of this Act and for the purposes of the references in section 8(3) and (4) of this Act to a participator's share of the oil won and saved from an oil field in a chargeable period.

(a) Gas Act 1986 (c.44) s. 67(1) *and* Sch. 7 para. 20 *from a date to be appointed by the Secretary of State. Previously* "(*a*) that any consent given under [section 29 of the Gas Act 1972(ax)] for the supply *or use*(bx) of the gas applies to the supply of the gas under the contract mentioned in sub-paragraph (2) of that paragraph *and to the use of the gas supplied under it*(bx); and (*b*) that no consent is required under [that section(ax)] for that supply *or use*(bx) if no such consent would be required if that contract were in fact made by the participator in question."

(b) 1980 s. 109(7) *in relation to chargeable periods ending after* 31 *December* 1979.

(c) *See—*

1982 s. 134 *and* Sch. 18—*alternative valuation of ethane used for petrochemical purposes.*

1986 s. 109—*alternative valuation of light gases where an election is made under* 1986 s. 109 *and accepted by the Board.*

(ax) Oil and Gas (Enterprise) Act 1982 (c. 23) s. 37 *and* Sch. 3 para. 22 *and* S.I. 1982 No. 1059 (C. 33) *with effect on* 18 *August* 1982. *Previously* "section 8 or 9 of that Act" *and* "those sections".

(bx) *Repealed by the* Oil and Gas (Enterprise) Act 1982 (c. 23) s. 37 *and* Schs. 3 para. 22 *and* 4 *and* S.I. 1982 No. 1059 (C. 33) *with effect on* 18 *August* 1982.

State of Alaska
Department of Revenue
Oil and Gas Audit Division

M E M O R A N D U M

TO: Hugh Malone
Commissioner, Department of Revenue

ATTN: James Rhode
Special Assistant to the Commissioner

FROM: Roger Marks
Petroleum Economist

DATE: February 23, 1988

SUBJECT: North Sea Taxation Structure

Pursuant to your request, we have compiled a synopsis of the petroleum taxation structure for Great Britain and Norway. As these structures have been subject to frequent modification, for simplicity we have only described the current structure, given the best information available to us.

Great Britain

Petroleum rights accrue to the government through the Petroleum Production Act of 1934. The Continental Shelf Act of 1964 grants jurisdiction over the continental shelf. Licenses to explore and produce are granted through periodic licensing rounds. Awards are made by discretion, with technical and financial attributes, as well as contributions to the economy as criteria.

The Oil Taxation Act of 1975 provides the basis of taxation. There are three main taxes: royalties, the Petroleum Revenue Tax (PRT), and corporate income taxes.

Royalties are at a one-eighth rate, but applied to different bases. In the first licensing rounds they applied to gross revenue at the wellhead, which is the landed value less transportation and initial treatment expenses. In later licensing rounds they were based on the landed price. Properties leased since 1982 have had no royalties.

The PRT is a tax on profits, and is levied field by field in the North Sea. Currently the tax has a 75% rate applied to a base of gross revenues minus allowances. The allowances include accrued field losses, operating costs, royalties, exploration costs, and an "uplift" allowance of 35% (or 135% of capital costs). The uplift is restricted to expenditures incurred up to the time of payout, including the uplift. An accumulated five million tons is exempt from the tax, with a maximum of 0.5 million tons in any one year. Since 1983 new fields get an accumulated 10 million ton exemption with a maximum of 1 million tons a year.

If gross profits for a field are less than 15% of the accumulated field investment the PRT is zero. There is a maximum PRT of 80% of the excess of gross profits over 15% of the field investment.

Since 1987 the producer has had the option to utilize a crossfield allowance, where 10% of the development costs prior to payback can be applied against the PRT income from other fields. No uplift is available on the expenditure to which the allowance relates.

Research and development costs not related to specific fields can be deducted from PRT income after three years.

Petroleum is subject to normal corporate income taxes. In 1974 a "one way ring fence" was established around the North Sea, where losses and capital allowances outside could not be set against income within, but losses within could be set against outside income.

The corporate tax rate is currently 35%. Exploration and development drilling costs can be expensed. Other deductions include losses, operating costs, interest, royalties, the PRT, and depreciation, figured on a 25% declining balance basis.

Norway

Norway's structure is similar to Britain's. Mineral rights are vested in the Crown and licensing is done by discretion. There are three main taxes: the royalty, corporate income taxes, and a Special Tax, + capital tax

Royalties are part of the license. The base is gross revenues at the production area point of shipment. The rate is 10% for licenses granted prior to 1973, and since then a sliding scale royalty has been applied, with rates from 8% tp 16% as production goes from under 40 000 barrels per day up to over 350,000 barrels per day. The rates apply to total production from the field, not increments. The royalty is zero for fields licensed since 1986.

There are two similarly structured income taxes, a national income tax and a municipal tax. For petroleum, the latter is collected and utilized by the central government. The rates are 27.8% and 23%, respectively.

Exploration costs, license fees , and royalties are allowable deductions. Depreciation is figured on a six year straight line basis, commensurate with the expenditure.

Deficits accumulating over the previous 25 years are deductible as losses. The deduction in any year is limited to one-third of the total deficit in the previous 15 years, so that total deductions are distributed over a minimum of three years.

Only 50% of the losses from other activities in Norway can be deducted from petroleum income. There are no restrictions in setting petroleum losses against other income.

The Special Tax applies to offshore operations only. It is not deductible for income taxes.

The tax currently has a 30% rate. Its base is the same as for the income tax, except there is an additional special allowance of 6-2/3% of the value of capital expenditures (historical cost) (not including exploratory expenses) brought into use during the previous 15 years. For fields licensed since 1986 there is a 15% volume allowance.

State of Alaska
Department of Revenue
Oil and Gas Audit Division

MEMORANDUM

To: Hugh Malone, Commissioner

Thru: William Floerchinger, Director

From: Charles Logsdon, Petroleum Economist CL

Date: April 25, 1988

Subject: The Petroleum Tax Structure of the United Kingdom and Norway

The attached information contains general and detailed information about the tax structures of United Kingdom and Norway. Roger has drafted a very short summary of the two fiscal regimes. What follows is my own brief summary of of the value issue which has a similar context to that we face here in Alaska.

UNITED KINGDOM

Oil Revenue Source:

1. Royalty
2. Petroleum Revenue Tax
   (Tax on production profit)
3. Corporate Income Tax
   (Tax on trading profit)

Value of Production:

1. Arms length sales or market value.
2. Market value = evidential base of comparable arm's length sales
3. Market value = at time of delivery. Contracts for delivery in valuation month starting 1st day of month preceding delivery and ending on middle day of month of delivery.
4. Bonafide "3rd party" acceptable rather than calculated market value. See Brent Blend Exemption

NORWAY

Oil Revenue Source:

1. Production Fee (Royalty)
2. Income Tax
3. Special Petroleum Tax
   (+ offshore income tax)
4. Capital Tax

Value of Production:

1. Norm price. Price fixed by a price board quarterly based on an assessment of what price would characterize "independent parties in a free market"

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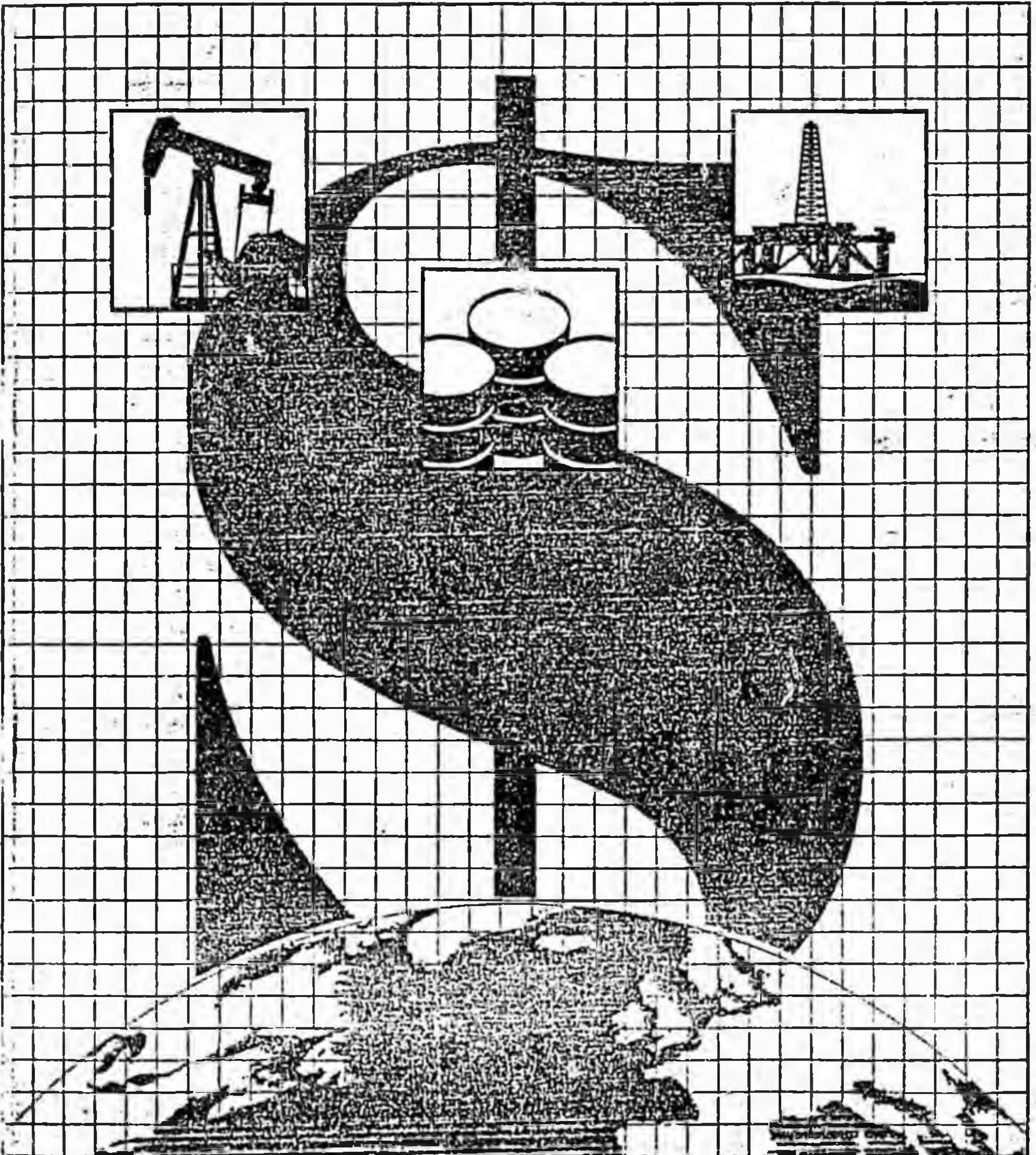
OIL & GAS AUDIT DIVISION

PETROLEUM RENT COLLECTION

AROUND THE WORLD



BY ALEXANDER KEMP WITH POSTSCRIPT BY CAMPBELL WATKINS

:) United Kingdom

ı the United Kingdom petroleum rights are vested in the ›vernment by the Petroleum (Production) Act of 1934, which was ›tended to the U.K. Continental Shelf by the Continental Shelf Act ı 1964. The great bulk of petroleum exploitation activity is offshore. i:ences to explore for and produce petroleum are awarded through ·riodic licence rounds, of which there have been 10 to date. Blocs ıve usually been awarded by a discretionary system, though a ımber have been awarded by competitive cash-bonus bidding. ıder the discretionary system, bids are assessed against a number of ·iteria which emphasize the technical and financial competence of ıe applicants and their contribution to the U.K. economy. Over the :ars greater attention has been paid to such criteria as the balance of ıyments, the growth of industry and employment, and the promotion research and development work in the United Kingdom.

Special taxation of petroleum exploitation in the United ingdom dates to 1975, when the Oil Taxation Act was passed. This ı ensured that three different taxes would be imposed on North Sea l exploitation. The first was the traditional royalty which accrued to ı: state in the United Kingdom as landlord, the second was the troleum Revenue Tax, and the third was normal corporation tax.

The traditional royalty rate is 12½ per cent, but the effective ·alty depends on the base to which the rate is applied. In the first ır licensing rounds the base was gross revenues at the wellhead; is was calculated from landed values less transport and initial :atment costs. The U.K. Inland Revenue in practice allowed as luctions from the landed price not only transport costs from the lds in the North Sea but also around 70 per cent of production ıtform costs, representing necessary initial treatment costs. Given : magnitude of these costs, the effective royalty as a proportion of : landed price could be reduced significantly below 12½ per cent. ›m the Fifth Licensing Round onwards, the base for the royalty has n changed, becoming 12½ per cent of the landed price. In the 1983 dget a major concession was made to stimulate development of new ılds: for fields for which development approval is given from April 1, 32, the royalty is abolished; this concession does not apply to fields the southern basin (which have all been found to be gas, to date) l to onshore activities.

The Oil Taxation Act of 1975 introduced the Petroleum Revenue : (PRT) as a special tax on profits from North Sea oil exploitation. is tax is levied on a field-by-field basis. The original rate of tax was per cent, and the base was gross revenues minus the sum of a ımber of allowances. The allowances were accrued field losses, :rating costs, royalties, 175 per cent of the main field capital costs, ld-related exploration costs, and an oil allowance equal to the value

of 10 million tons of oil (with no more than 1 million tons eligible for use as an allowance in any one year). Interest on loans was not allowed as a deduction, and as compensation for this the so-called "uplift" of 75 per cent of capital expenditure was introduced. The capital allowance deduction was allowed on a 100 per cent first-year basis.

The uplift and oil allowances were designed to give particular help to small and less profitable fields. Further help was provided by the safeguard and tapering (or annual limit) provisions. In broad terms these state that if gross profits in any year are less than 30 per cent of accumulated field investment, the PRT becomes zero; and the maximum PRT in any year is 80 per cent of the excess of gross profits over 30 per cent of field investment.

Since 1975 several changes have been made to the PRT. In the Finance (No. 2) Act of 1979 the rate of PRT was increased to 60 per cent as of January 1979. At the same time the uplift on capital expenditure was reduced from 75 per cent to 35 per cent and the oil allowance was reduced to 5 million tonnes, with no more than 0.5 million tonnes being allowed in any one year. As of November 1979, in the Petroleum Revenue Tax Act of 1980, the dates for payment of the PRT were advanced by two months. In the Finance Act of 1980, the rate of PRT was increased to 70 per cent as of January 1980.

Changes to some of the PRT allowances were introduced in the 1981 budget. From January 1981, the 35 per cent uplift on capital expenditure has been restricted to expenditure incurred up to the time when cumulative incomings from a field first exceed cumulative outgoings (field payback). For the purposes of this calculation, outgoings are defined to include any uplift on capital expenditure. Expenditure incurred after this cut-off period will not attract uplift.

The 1981 budget also saw changes to the safeguard and tapering provisions, introducing a restriction on the time period during which these concessions apply. The period is now half as long again as the time it takes for a field's payback to be achieved; the calculation is in terms of chargeable periods, each of which is six months, and outgoings are again defined to include any uplift on capital expenditure. Since eligibility for safeguard and tapering is calculated on a six-month chargeable period, instead of annually, from January 1, 1981, the maximum PRT payable in any period has thus become 80 per cent of the amount by which gross profits exceed 15 per cent of accumulated investment.

In the budget of 1981 the government also introduced a new tax, the Supplementary Petroleum Duty (SPD), with effect from January 1981. The rate of this duty was 20 per cent, with the base being gross revenues minus an annual allowance of one million tonnes. The duty, levied on a field-by-field basis and payable monthly, was deductible

for PRT and corporation tax. After much protest by the oil companies, the Chancellor of the Exchequer announced in his budget of March 1982 that the SPD would be abolished from the beginning of 1983.

The announcement of the abolition of SPD was accompanied by the raising of the PRT to 75 per cent and by the introduction of advance PRT (APRT), also to take effect from January 1983. The APRT was to be levied in exactly the same way as the SPD, with a rate of 20 per cent and a base of gross revenues minus an allowance of one million tonnes per year. The tax would thus take effect from the first day of production. Payments could be credited against normal PRT; where no PRT was payable, or where liability was insufficient to absorb all APRT, excess APRT would be carried forward and set off against future PRT. APRT payments would be included as deductions in computing the payback period for a field. Liability to APRT would be removed after five years of payment of the tax. Repayment of any APRT which had not been fully set off against normal PRT would also be made after five years of liability rather than at the end of field life. In the budget of 1982 plans were announced to phase out the APRT. The rate was reduced to 15 per cent for the period July-December 1984, 10 per cent for 1985, and 5 per cent for 1986; the tax was abolished at the end of 1986.

In the 1983 budget further major PRT concessions were made. Up to 1983, exploration costs had to be accumulated and could be set against income only from the field to which the exploration related. Only if the exploration was clearly abortive could the costs be set against other income for PRT purposes. Since 1983 exploration costs can immediately be set against any other PRT income and are deductible on a 100 per cent first-year basis. In the 1983 budget the oil allowance for new fields was doubled to 10 million tonnes, with a maximum of 1 million tonnes being deductible in any one year. This concession does not apply to the southern North Sea gas fields or to onshore fields.

In the Finance Act of 1987, further PRT concessions were made for fields outside the southern sector. The investor now has the option of utilizing a new crossfield allowance, equal to 10 per cent of development costs prior to field payback and applicable immediately against PRT income from other fields. No uplift is available on the expenditure to which the allowance relates. A further concession permits research and development costs not related to a specific field to be deducted from any PRT income after a three-year period.

Normal corporation tax applies to petroleum exploitation. Since 1974 there has been a one-way ring fence established around petroleum exploitation. This means that losses and capital allowances emanating from outside the ring fence cannot be set against income arising within the ring fence. On the other hand, losses arising within the ring fence can be set against other, non-ring fence income.

The rate of corporation tax was 52 per cent from 1973 to April 5, 1983. For financial year 1983-1984 the rate was 50 per cent; for 1984-1985, 45 per cent; for 1985-1986, 40 per cent; from 1986-1987, 35 per cent. While the tax rates are being reduced, the rates of relief for investment in plant and machinery are also being reduced – from 100 per cent first-year basis up to March 14, 1984, when the rate became 75 per cent – to March 31, 1985, 50 per cent to March 31, 1986, and 25 per cent on a declining-balance basis thereafter. Relief for exploration and development drilling continues to be on a 100 per cent first-year basis. Losses, operating costs (including loan interest), royalties, and PRT are all allowable deductions, but the APRT is not an allowable deduction.

In this study the emphasis is on the operation of the fiscal system with regard to new investments. Accordingly, the system applicable to new fields has been incorporated in the detailed empirical work. This means that the provisions for royalty relief, the higher oil allowance for PRT, and the immediate relief for exploration costs are all included. Where immediate relief for exploration costs is taken by investors, the uplift benefit is forgone. This is the method that investors have preferred and so is included in this study.

Participation by the British National Oil Corporation (BNOC) has been a feature in some licences. For licences awarded under the first four rounds, participation was introduced retrospectively on a "voluntary" basis – BNOC was given the right to purchase 51 per cent of oil produced in the different fields. Thus, to quote from a famous speech of a government minister, Sir Harold (later Lord) Lever, at the time this was introduced in the mid-1970s, participation meant "no gain no loss" to the oil companies. Under the Fifth Round terms, BNOC was a compulsory equity partner, to the extent of 51 per cent, in all licences; it was also a full risk-sharing partner for both exploration and development costs, and so the arrangement is really a joint venture. Under the Sixth Round terms, BNOC's privileges were further increased – participation was on a carried-interest basis and the oil companies were asked to bid interests to BNOC of 51 per cent or more; exploration costs would be reimbursed only when a field was discovered and declared commercial. By the time the Seventh Round was announced (1980), there had been a change of government. The Conservative government removed BNOC's privileges, and BNOC had to compete for licences on the same basis as any other oil company, though it was still given the right to buy 51 per cent of all oil at market prices. In the Eighth Round the same arrangements as those of the Seventh prevailed. Since then the exploration and production interests of BNOC have been privatized in a new company,

Britoil. BNOC continued to exist as an oil purchaser and trader to the extent of 51 per cent of production until 1985, when the corporation was abolished. The Oil and Pipelines Agency was set up to maintain the right to purchase participation oil but these rights are not being exercised. Thus, in the present study no government participation is included.

The government has one discretionary fiscal power which it can utilize to foster the development of marginal fields. The Department of Energy can remit royalties where it is convinced that the requirement to pay royalties is discouraging the development of a field or causing premature abandonment to be considered. The remission of such royalties is free of PRT and corporation tax (i.e., no additional PRT or corporation tax is payable, even though royalties are normally deductible items for these two taxes). To date several applications for remission of royalties have been made, but none has been granted.

(3) Norway

The exploration and development of offshore petroleum in Norway is governed by the Continental Shelf Act of 1963, the Royal Decree of 1972 (as amended), and the Petroleum Activities Law of 198[illegible] In Norway mineral rights are vested in the Crown. Licensing is done by a discretionary system, the criteria including technical and financial competence, contribution to the Norwegian economy (in particular the balance of payments and industrial growth and development), exploration program offered, and government participation offered. There are three main taxes levied on petroleum exploitation, namely, royalty, income tax, and Special Tax.

As in the United Kingdom, the royalty is part of the licence. The base of the royalty is gross revenues at the production-area point of shipment. For licences awarded before December 1972, the rate is 10 per cent; for licences awarded since December 1972, a progressive schedule of royalty rates applies, as shown in Table 3.4. The rates apply to the *total* production from a field. The tax is thus applied on a slab basis, not an incremental one. The rules also state that when production from a field declines, the royalty rate will fall as well, according to the schedule, except that it may *not* fall below 12 per cent. On gas the royalty rate is fixed at 12½ per cent. Section 26 of the Royal Decree of December 1972 gives the government the power to fix lower royalty rates "if the sea depth, capacity per well, or other conditions so require," but to date there have been no reductions in royalty rates.

There are two income taxes payable by all companies operating in Norway—National Income Tax, at the rate of 27.8 per cent; and Municipal Tax, at the rate of 23 per cent. With regard to petroleum, the Municipal Tax is collected and utilized not by the local governments but centrally. In 1975 the Norwegian government introduced a tax package on North Sea operations which maintained the royalty provisions described above but substantially changed income taxation.

Table 3.4
Royalty Rates on Oil Production in Norway

Average Field Production (barrels per day)	Rate of Royalty (%)
Under 40,000	8
40,000 and under 100,000	10
100,000 and under 225,000	12
225,000 and under 350,000	14
350,000 and above	16

The 1975 act introduced allowances which apply equally to both income taxes. Deficits accumulated over the previous 25 years are deductible as losses, although there is a restriction on the rate at which such losses can be deducted. The deduction in any one year is limited to one third of the total deficit in the previous 15 years, so that the total deductions have to be distributed over a minimum of 3 years. Eligible costs include exploration costs, various licence fees, and royalties. Only 50 per cent of losses incurred from other (non-Continental Shelf) activities in Norway may be deducted from Shelf income. Had the 1975 act not stipulated this restriction, companies would have an incentive to invest in non-Shelf activities, and tax revenues from North Sea oil exploitation would be postponed. The provision means, in effect, that 50 per cent of non-Shelf operating losses may be set against Shelf income, as can 50 per cent of the costs of investing in, say, a refinery or marketing facilities. On the other hand there is no restriction on the ability to set losses incurred in Shelf operations against income from other activities in Norway. Thus, there are still advantages to be obtained from integrated operations in Norway. However, losses or deficits incurred abroad are not allowed as deductions against North Sea income in Norway.

The 1975 act also introduced special depreciation provisions for North Sea operations. The normal depreciation allowances were considered too restrictive for the size of the investments and risks

incurred in the North Sea, and the additional or initial allowances available in existing income-tax legislation were not considered suitable. Accordingly, new provisions were introduced. These stated that deductions for capital expenditure incurred in production and transport facilities could be claimed to the extent of 16⅔ per cent per annum from the date at which the assets were brought into use. Thus, a six-year straight-line depreciation system was introduced, but it effectively commenced only when oil production started. This last qualification has been of considerable significance. It has meant that, when an enterprise was in receipt of income from a field in the North Sea and was in a tax-paying position, it could *not* immediately set depreciation allowances relating to a new field against the income from its existing operations; such offsetting was not allowed until production from the new field started. There is no ring fence around each field in Norway, but the way in which the depreciation allowances were given produced a rather similar effect.

The most widely publicized innovation in the 1975 act was the Special Tax, which applies only to offshore operations. The tax was introduced at the rate of 25 per cent. The base for this tax is the same as that for income tax, with important modifications. In addition to the depreciation and other allowances for income tax discussed above, there is a further special allowance. In the 1975 act the special allowance, in any one year, was equal to 10 per cent of the value of capital expenditure (at historic cost) on offshore activities brought into use over the preceding 15 years. Capital equipment includes investments in transport systems and related terminal facilities; exploration expenditure is not allowed as part of the special allowance. If production from a field lasted 15 years, the total value of the special allowance for that field would thus be 150 per cent of the value of capital expenditure. The special allowance does not come into effect until production from the field has actually started. This is important when the tax implications of a second field are being analyzed: the ability to utilize the special allowance from the capital expenditure on the second field against the income of the first field is restricted to the time when production commences on the second field. If a field's producing life is less than 15 years – and this is likely to be the case for many of the smaller fields – then, of course, the full allowance of 150 per cent of capital expenditure cannot be utilized. Such unutilized allowances from one field may, however, be carried over and used when calculating the tax base for Special Tax on a second field. This is because there is not, strictly speaking, a ring fence around each field for Special Tax purposes.

Special Tax is not deductible for income-tax purposes. In June 1980, the fiscal system in Norway was revised, with the changes mainly relating to the Special Tax. The rate was increased from 25

per cent to 35 per cent. In addition, the special allowance in any one year was reduced to 6⅔ per cent of accumulated investment over the previous 15 years. It was made clear, however, that the equivalent of 100 per cent of capital costs would always be allowable over the life of a field even when strict application of the rule would not suggest eligibility for such a total; this was a concession to help short-lived fields. The 1980 rules stated, however, that utilization of the special allowance could not begin until one year after production starts. A further change stipulated that all losses would now be eligible for write-off whenever sufficient income becomes available. There was a change concerning the timing of payment of both income taxes and the Special Tax – before 1980 a lag of around 12 months occurred between the liability for these taxes and their actual payment; this lag has now been reduced to 6 months.

In the summer of 1986 major concessions were made to the fiscal system. From January 1, 1987, the rate of Special Tax was reduced to 30 per cent, and as of that date depreciation for both Special Tax and income tax commences from the time that the expenditure is incurred. Uplift is no longer available on capital expenditure after January 1987 but, as a transitional measure, uplift on past expenditure continues according to the old rules. For new fields (development approval since January 1, 1986) royalties are reduced to zero. Further, for Special Tax on new fields a volume allowance equal to 15 per cent of production is now available.

The fiscal position regarding dividend payments is complex, the distinction between National Income Tax and Municipal Tax being highly significant. When a company makes a distribution, the dividend payment is deductible from the National Income Tax but not from Municipal Tax, and dividend payments are not deductible for Special Tax. When a dividend is declared, Norwegian shareholders pay income tax on the dividend. When the distribution is made by a Norwegian subsidiary to its foreign parent, a special withholding tax is paid. The rate of withholding tax is determined by the double tax agreements between Norway and the foreign countries concerned; on subsidiaries of U.S. and U.K. companies the rate is currently 15 per cent.

In Norway joint-stock companies are obliged to maintain a reserve fund, whose minimum required amount is the higher of 20 per cent of the company's share capital or that amount which, when added to the share capital and revaluation fund, equals the company's debt. If the defined minimum has not been attained, then the company has to set aside funds according to the following rules:

1. Amounts equal to 10 per cent of annual profits, the latter defined as excluding any part of profits required to cover losses from previous years.
2. A further amount equal at least to any dividend declared by the company in excess of 10 per cent of the sum of the share capital, revaluation fund, and reserve fund at the beginning of the financial year.
3. Any share-subscription premium less the costs of establishing the company or increasing its capital.

Contributions to the reserve fund are, of course, made before payment of taxes. This reserve-fund legislation restricts the ability of a company to pay dividends.

Given the tax regulations and rates discussed above, it is important to clarify the dividends that can be paid. The maximum dividend payable may be calculated in the following manner (ignoring reserve-fund contributions and the capital tax, which is very small):

$$\begin{aligned} \text{Maximum Dividend (MD)} &= \text{Profit before tax (P) - Special Tax (ST) - National Income Tax (NIT) - Municipal Tax (MT)} \\ &= P - ST - 0.278\,(P - MD) - 0.23\,(P) \\ &= 0.492\,(P) - ST + 0.278(MD) \\ &= \frac{0.492\,(P) - ST}{0.722} \end{aligned}$$

When maximum dividend is paid, the various corporate taxes payable in 1987 are as follows:

NIT = 0.278 (P - MD)

MT = 0.23 (P)

Dividend Tax (DT) = 0.15 (MD)
(for United States and United Kingdom)

ST = 0.30 (P - Special Allowance)

Oil companies operating on the Continental Shelf, like other enterprises on land, pay a further tax – the capital tax. For many years this was at the rate of 0.7 per cent of the value of net capital, but the rate has been progressively reduced in recent years and it is now 0.4 per cent. The base includes production, transport, and storage facilities; stocks of products produced; and securities and bank deposits. As far as offshore operations are concerned, the base does *not* include the value of crude oil in the reservoirs. The capital tax is not deductible for income-tax or Special Tax purposes.

Participation by the national oil company, Den Norske stats oljeselskap a.s. (Statoil), has taken place since the company was founded in 1972. In early participation schemes, some "net profit" agreements were concluded, but for some years now carried-interest agreements have been preferred. Statoil's interest is carried by the oil companies until a commercial discovery is made, at which point Statoil participates. In early agreements, Statoil agreed to pay its share of exploration costs. In most later agreements only development and operating costs were payable by Statoil, though in recent agreements with other Norwegian oil companies it has agreed to pay its share of exploration costs.

In early participation agreements there was a fixed, flat Statoil share. From the Third Licensing Round up to the Tenth Round participation agreements were concluded on a sliding-scale basis, which means that Statoil's share of *total* production increases with the size of peak production from the field. The procedure adopted is that Statoil's share is estimated at the time when a field is declared commercial; if the initial estimates prove accurate, then Statoil's interest would remain constant throughout the life of the licence; on the other hand, if estimated peak production is subsequently changed, Statoil's share would be retroactively altered. There might, of course, be several such retroactive adjustments.

The precise scales are the subject of negotiation between the oil companies and Statoil and are generally not published. A typical scale in the second half of the 1970s or early 1980s would give Statoil a minimum share of 50 per cent, increasing according to the schedule shown in Table 3.5. By the Seventh, Eighth, and Ninth Rounds the sliding scales had become truncated and the scale shown in Table 3.6 was reported as typical.

By 1983 there was growing concern about the enormous direct role that Statoil was playing in the whole economy. The Mellbye Committee was set up and eventually in October 1984, new regulations regarding participation were introduced whereby the state took a direct share in new fields and Statoil was given a reduced role, as is illustrated in Table 3.7. The total government share was to remain unaffected.

By the time of the Tenth Round (1985-1986) oil prices were falling. In an attempt to retain investor interest, participation rates have been reduced. Under this round the total state share is in the 60 to 65 per cent range, with Statoil having a direct stake of 20 per cent on average. In the summer of 1986, a further concession was introduced – on new licences investors are no longer obligated to carry the state's share at the exploration stage.

Table 3.5
Statoil Participation – Typical Sliding Scale

Maximum Licence Producing Rate (thousands of barrels per day)	Statoil Working Interest (%)
0 - 75	50
75 - 100	52
100 - 125	54
125 - 150	56
150 - 170	58
170 - 190	60
190 - 200	61
200 - 210	62
210 - 230	63
230 - 250	64
250 - 270	65
270 - 290	66
290 - 310	67
310 - 330	68
330 - 350	69
350 - 370	70
370 - 390	72
390 - 410	74
410 - 430	76
430 - 450	78
450 and above	80

Table 3.6
Typical Statoil Participation, Recent Rounds

Peak Production (thousands of barrels per day)	Rate of Statoil Participation (%)
0 - 100	65
100 - 250	75
250 and above	80

Source: Norges Offentlige Utredninger, *Organiseringen av statens deltagelse i petroleumsvirksomheten* (Oslo: Universitetsforlaget, 1983), p. 42.

Table 3.7
Estimates of Likely Structure of Norwegian State Participation, Selected New Fields

Field	Direct State Share (%)	Statoil Share (%)
Sleipner	30	25.8
Oseberg	49.24	14
Troll 31/2	54	21
Troll (rest)	73	12
Gullfaks	73	12

(4) Indonesia

In Indonesia the basic legal framework for petroleum exploitation is contained in the Oil and Gas Law of 1960, Law No. 1 of 1967, the Foreign Investment Law, Law No. 11 of 1967, and Law No. 8 of 1971. Other relevant legislation is contained in presidential and ministerial decrees. The Oil and Gas Law of 1960 abolished the concession system. Law No. 8 of 1971 established the state company, Pertamina, and permitted it to enter into production-sharing agreements with foreign oil companies.

Indonesia has been the pioneer of production-sharing agreements whereby the oil companies are contractors to the state oil company. In the Indonesian agreements contractors pay both signature and production bonuses. The details of these vary from one contract to another with figures in the range $1 to $5 million being typical. Production bonuses vary with the level of production. This study has assumed bonuses of $5 million at 20,000 barrels per day (b/d), $10 million at 50,000 b/d, $20 million at 100,000 b/d, and $40 million at 200,000 b/d. Bonuses are not recoverable costs under the production-sharing scheme. They are deductible for income-tax purposes, but they are grossed up in order not to reduce the government take.

For cost-recovery purposes, under the production-sharing scheme, exploration costs and intangible drilling costs have been deductible as soon as income from the contract area in question permits. Tangible capital costs have been recoverable in the form of depreciation, which is allowed over one half of the depreciation life by the double-declining-balance method. The contractor has the option to switch to the straight-line method whenever it is advantageous. There is a one-time investment tax credit equal to 20 per cent of tangible development costs. The credit is deducted from gross production before production sharing takes place.

After cost recovery and investment tax credit, the remaining oil has usually been split 65.9091:34.0909 (on a per-tax basis) in favour of Pertamina; on a post-tax basis this has been equivalent to 85:15 in Indonesia's favour. There have been some divergences from this figure—for example, a major agreement with Caltex in late 1983 provided for an 88:12 split.

In Indonesia, contractors have been obliged to provide a certain amount of production for the domestic market on preferential terms. The maximum obligation has been 25 per cent of the contractor's pre-tax share. For the first five years of production from a contract area, the oil can be sold at full market value but after that a figure of only $0.20 per barrel can be charged. During 1986, as an incentive to investors, this domestic-market obligation was abolished for new agreements.

Contractors have to pay corporate income tax on their taxable profits. Operating costs, exploration costs, tangible drilling costs, and depreciation are all deductible in order to obtain taxable income. Until recently the corporate tax rate was 46 per cent. There is another tax, known as the Tax on Interest, Dividends and Royalties, which is payable regardless of whether dividends have been remitted or not. This is at the rate of 20 per cent of profits after corporation tax. There has thus been a combined tax payable of 56.8 per cent [0.46 + 0.2 (1 - 0.46)].

In 1984 the income tax in Indonesia was reformed.[2] The corporate rate was reduced to 35 percent, so the combined rate is thus 48 per cent. Depreciation terms were also changed; for many items of equipment employed in petroleum exploitation, rates of 25 per cent on a declining-balance basis are available with some items having rates of 10 per cent. Intangible drilling costs continue to be expensed. Although the new tax law took effect from January 1984 onwards, exploration agreements in 1984 and in 1985 were signed under the old terms.[3] The precise application of the new laws to petroleum contracts remains unclear. The government does not wish its total take to be decreased as a consequence of the change in income-tax rate. For the government's take to remain unchanged would imply a pre-tax oil-sharing split of 72:28 in Indonesia's favour. This ratio, as well as the 65.9091:34.0909 one, has been employed in the present study.

In Indonesia the rules require investors to set up separate companies for each contract area, and each company is assessed separately for income tax. The production-sharing arrangements are of curse also on a contract-area basis. It follows that there are no significant fiscal advantages from ongoing investment, although if more than one field were discovered in one contract area, there would be significant advantages when the second field was developed.

(5) Malaysia

Under the 1974 Petroleum Development Act, petroleum concessions in Malaysia were terminated and replaced by production-sharing agreements. The national oil company, Petronas, was established and given exclusive rights to explore for and produce petroleum and to negotiate production-sharing agreements with oil companies.

The current fiscal package in Malaysia consists of production-sharing arrangements as well as royalty, income tax, Export Tax, Excess Proceeds Tax, and contribution to a research fund. There are also a number of bonuses payable—signature bonuses, which have averaged around $1 million in recent years; discovery bonuses, which have been around $2.5 million per commercial discovery in recent

(2) United Kingdom

The state's shares of economic rents under price scenarios expected in 1985 are shown in Figure 6.13 for a 10 per cent discount rate. The fiscal system is seen to behave such that under rising real prices the take is progressive across most of the fields and proportional on the VLV one. The absence of royalties on new fields combines with the effects of some features of both the PRT and corporation tax systems to produce this result. A combination of the "uplift" and safeguard provisions for PRT ensure that this tax is progressive in money-of-the-day terms and sometimes in present-value terms. For an ongoing investor the ability to offset rapidly at least some of the costs of a new field development against other income produces a progressive income tax when profitability is reasonably high. The net result is a system which is progressive in relation to changes in profits caused by cost increases.

The same features ensure that at relatively low cost levels the fiscal system is progressive in relation to changes in profits caused by oil price movements. Unfortunately, in the range of costs now most likely to be found in the U.K. North Sea (namely, MC to HC), the fiscal system becomes regressive in relation to oil price changes; by the time HC is reached, the take is highest under falling real oil prices and lowest with rising real prices.

At a discount rate of 15 per cent the picture, as shown in Figure 6.14, is different. The fiscal system is highly regressive with respect to both oil prices and cost changes especially in the MC to HC range, which typifies present conditions. The allowances for PRT and corporation tax are insufficiently strong to prevent the government take from rising strongly as profitability falls. The reliefs for drilling costs are on a 100 per cent first-year basis and for plant and machinery costs at 25 per cent on a declining-balance basis; together they are too slow to prevent the take from increasing rapidly in a situation of falling real prices and rising costs.

From the trends discussed above it is no surprise to find that the system becomes more regressive in discounted terms under collapsed oil prices. Figure 6.15 shows the effects with a 10 per cent discount rate. Perhaps the most remarkable finding is that under MC conditions the system still produces takes well below 100 per cent of the economic rents. Even at a 15 per cent discount rate the takes under MC conditions remain tolerable on the LV field (84.7 per cent) and the VLV one (47.9 per cent).

The U.K. system is an adaptation of a conventional fiscal system. For an ongoing investor it is seen that, despite its many complexities, it produces an effect which encourages field developments over a wide range of oil price and cost conditions. The system does not always collect economic rents in a very accurate fashion, but compared with

many others in this study it is reasonably flexible to changes in the operating environment. The U.K. system has imperfections emanating from the basic problem that the chosen instrument is only indirectly related to its target: the appropriate target is the net present value at the investor's discount rate, and the U.K. fiscal system relates to this at best in a cumbersome manner, and at worst inaccurately.

Table 6.4 shows the position of the explorationist in the U.K. sector contemplating a program of $20 million on an ongoing basis for a constant real oil price of $27. The results show that, with a 1 in 5 chance of discovery, pre-tax EMVs are positive except at a discount rate of 15 per cent. With a chance of 1 in 10 the result is positive only at discount rates below 10 per cent, while with a chance of only 1 in 20 there is no positive EMV at any positive discount rate. The post-tax position generally reflects the favourable fiscal treatment given to exploration expenditure by an ongoing investor in the United Kingdom. Effective tax takes are low because the expected fields are small in size and pay little PRT. Exploration costs are relieved at 83.75 per cent on a 100 per cent first-year basis; in the calculations, this front-end relief to the ongoing investor is regarded as a negative tax. The ongoing investor also obtains the benefit of front-end relief for corporation tax on his expenditure on new field development. When the discounting process is undertaken, the effective tax take can sometimes be negative. This is especially the case when the subsequent tax payments on a discovered field are very small. The fiscal system is certainly helpful to ongoing investors.

In the U.K. sector, exploration programs of amounts larger than $20 million are not uncommon. With a program of $60 million it was found that pre-tax EMVs were negative at all discount rates when the chance of success was 1 in 10 or worse; with a 1 in 5 chance of discovery the EMV was positive at discount rates below 10 per cent. Effective tax rates (as defined above) were generally low in discounted terms and on some occasions negative. Thus, exploration incentives were hardly impaired by the tax system when viewed in discounted terms.

Under the collapsed oil price with an exploration program of $20 million, pre-tax EMVs are nearly always negative on the overall discovery rates of 1 in 5, 1 in 10, or 1 in 20, but the size of the negative EMV increases sharply as prospectivity declines. Post-tax EMVs are thus also generally negative as well. However, the fiscal system is, for the most part, not the main deterring factor; exploration incentives are low primarily because of the low level of oil prices in relation to likely exploitation costs. To an ongoing investor, effective tax rates are generally low and in discounted terms the tax system—with its

loss-sharing provisions resulting from the front-end loading of reliefs for expenditure—can hardly be said to be a deterrent.

Table 6.4
United Kingdom Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	122.4	77.3	29.1
5	51.4	36.1	23.6
10	10.6	12.1	-ve
15	-13.3	-2.2	-ve
Overall Discovery Rate: 1 in 10			
0	51.2	36.6	17.8
5	15.2	15.5	-ve
10	-5.7	3.0	-ve
15	-18.2	-4.5	-ve
Overall Discovery Rate: 1 in 20			
0	15.6	16.3	-ve
5	-2.9	5.2	-ve
10	-13.9	-1.5	-ve
15	-20.7	-5.6	-ve

Note: *-ve* indicates the tax take is negative.

In sum, from the viewpoint of economic efficiency, the U.K. fiscal system performs reasonably well when applied to new investments. The system is profit-related and does take account of differences in cost conditions likely to be encountered in the North Sea. Differences between pre-tax and post-tax rates of return are modest in comparison with many other countries discussed in this study. Reliefs for

exploration are fairly generous, and incentives for new exploration are comparatively strong. The U.K. system is noteworthy for the extent to which exploration risks are shared by the government. Development costs are also shared to a significant extent. The fiscal system is only indirectly related to the target of economic rents, however, and this inevitably produces some lack of accuracy. The PRT is very complex, and therefore costly, and the need to make some discretionary modifications as the operating environment changes is a further drawback.

Figure 6.13
United Kingdom
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

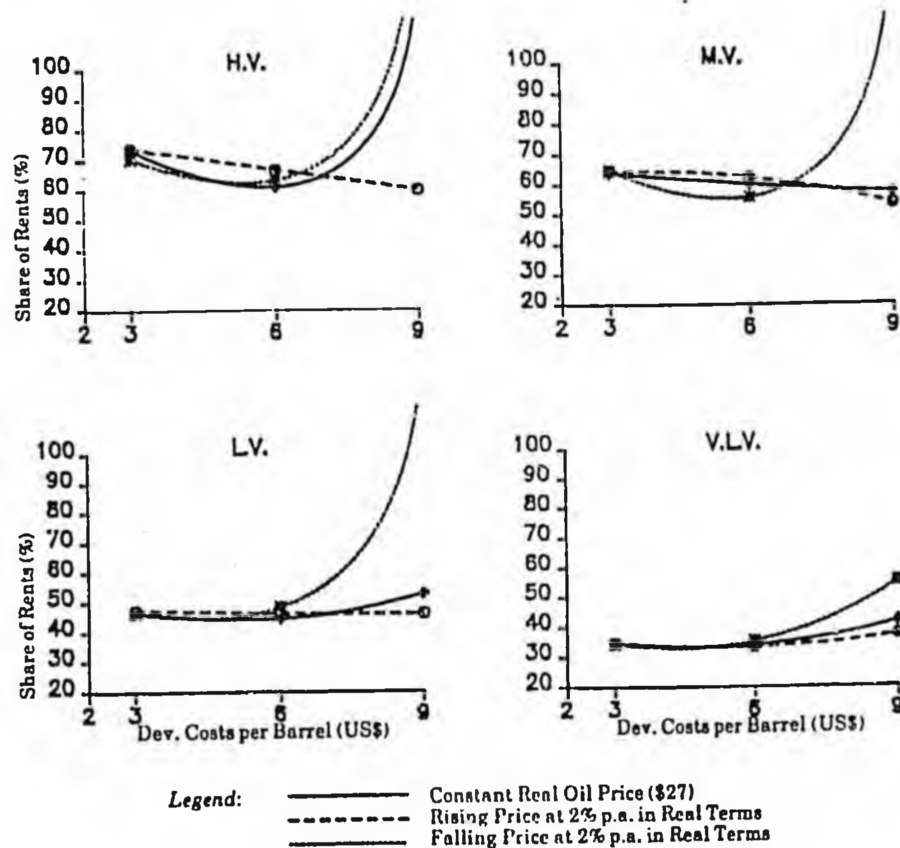


Figure 6.14
United Kingdom
Government Share of Economic Rents, 15% Real Discount Rate
1986 Price Perspectives

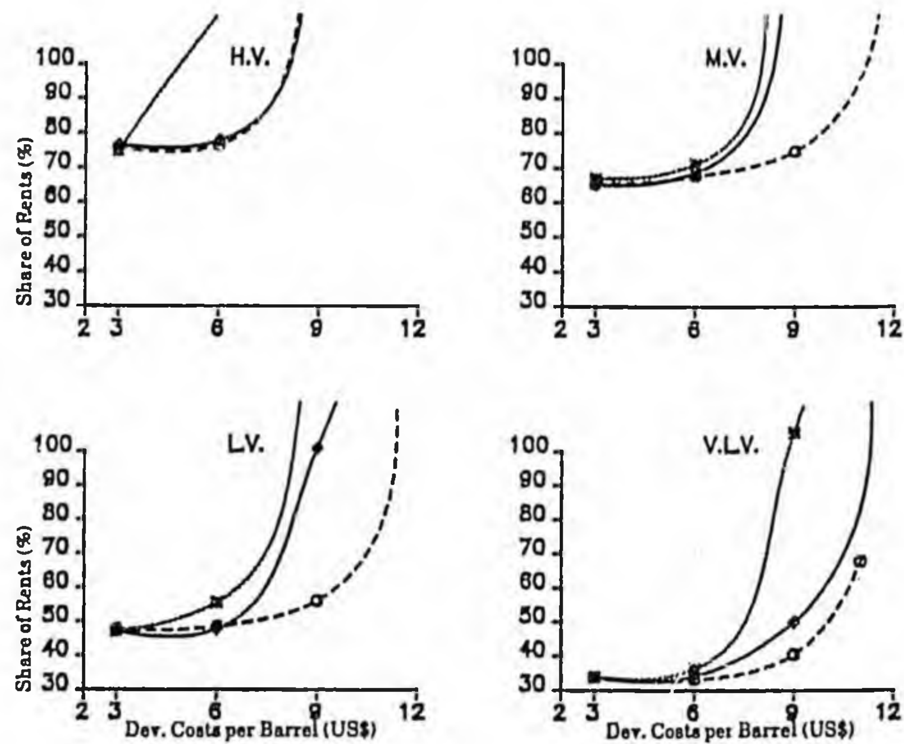
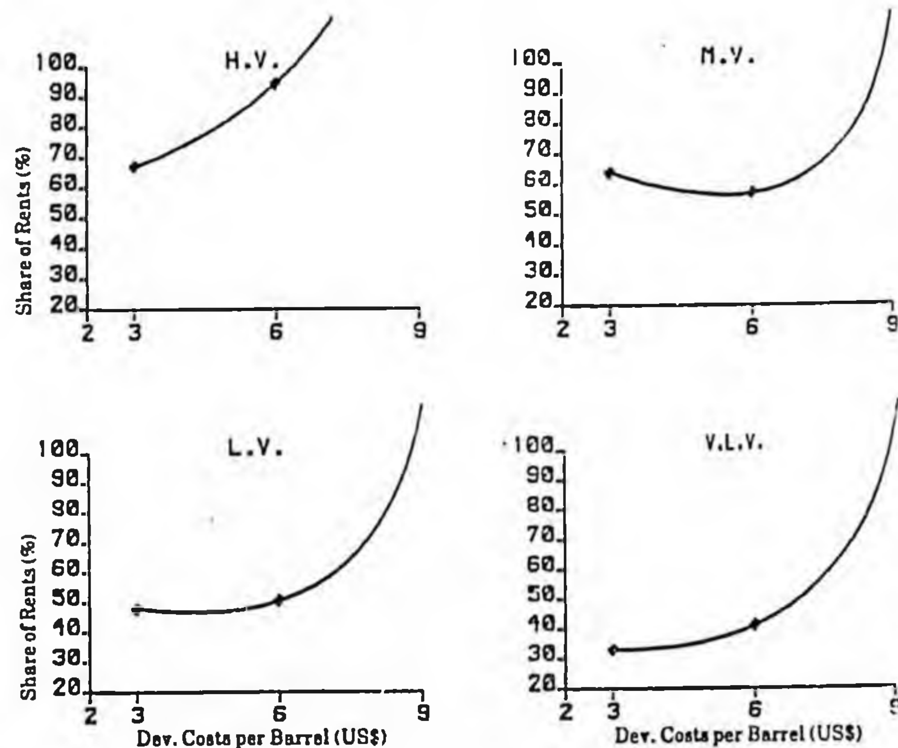


Figure 6.15
United Kingdom
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price



(3) Norway

The share of economic rents accruing to the state from petroleum exploitation in Norway is shown in Figures 6.16 and 6.17. Both figures illustrate the working of the Norwegian system under the oil price perspectives of 1985, at a discount rate of 10 per cent, but Figure 6.16 includes the government's take from taxes only, while Figure 6.17 includes state participation.

Figure 6.16 shows that the tax system is regressive and can collect more than 100 per cent of the rents. Projects will generally have development costs in the $3- to $6-per-barrel range, though some have considerably higher cost levels. It is seen that post-tax returns exceeding 10 per cent are sometimes not available when development costs attain $6 per barrel. On all fields the takes increase with lower oil prices. Similarly, the takes rise as project profitability falls due to cost increases. Several features of the fiscal system bring about this result—depreciation provisions for development costs for both income tax and Special Tax are on a six-year straight-line basis commencing with the year in which expenditure is incurred; this makes the system regressive in present-value terms, while the high marginal and average rates produce the high overall takes.

The position with government participation added (Figure 6.17) shows that with development costs of $3 per barrel participation significantly increases the state's share of economic rents. However, at development costs of $6 and more, the state's total share actually goes down compared with the tax-only situation, because the state company is then sharing in the project's post-tax present-value losses; in these situations the state would be better not to participate at all.

The fiscal system becomes both more severe and regressive the higher the discount rate employed. In Figure 6.18 the state's take (including participation) is shown at a 15 per cent discount rate. The difference between the take under falling real prices and that under rising prices becomes distinctly more marked. Under falling real prices the take is seen to become dramatically regressive and severe, on the large fields in particular.

As was discussed in Chapter 3, the institutional framework in Norway—with the dominant role of Statoil in investment decision making—suggests that the effective discount rates employed in project appraisal could be lower than in other countries, where private-sector firms are less inhibited. It is thus useful to consider the effects of the Norwegian fiscal system at lower discount rates. At a 5 per cent rate, on the assumption of constant real oil prices at $27 per barrel, the tax take on the VHV field is 73.9 per cent at LC and 79.0 per cent at MC conditions; on the HV field it is 73.6 per cent and 77.2 per cent respectively; on the MV field, 81.1 per cent and 76.7 per cent respectively; on the LV field the take is 73.4 per cent at LC, 76.2 per cent at MC, and 84.7 per cent at HC conditions. The conclusion that the size of discount rate employed makes a considerable difference to government takes in the Norwegian system is thus reinforced. If effective discount rates in Norway are lower than in other countries, there could be a significant effect on incentives.

Under the collapsed-price scenario the system is highly regressive in present-value terms. With development costs of $3 per barrel, the tax takes are around 80 per cent on all sizes of fields; as costs increase, the take rises sharply. The position with a discount rate of 10 per cent (participation included) is shown in Figure 6.19. At development costs of $6 per barrel the takes clearly exceed the rents. With a 5 per cent discount rate, tax takes are under 90 per cent under LC conditions on all fields; under MC conditions the takes are 85.4 per cent on the MV field, 83.8 per cent on the LV, and 83.3 per cent on the VLV one.

The position facing an explorationist in Norway contemplating a program costing $20 million, under the 1985 oil price perspective, is shown in Table 6.5. The pre-tax and participation EMVs are positive at all discount rates apart from the 15 per cent one. The expectation of relatively large fields in the Norwegian sector is a main factor in the determination of the positive outcomes. After tax and state participation, expected returns are usually reduced markedly by the fiscal system—EMVs to investors are now negative at positive real discount rates when chances of success are 1 in 10 or 1 in 20. The government shares to a large extent in the exploration risks through high and rapid write-off for exploration costs. This provides some compensation for the high tax takes on discovered fields. At high discount rates and very unfavourable prospectivity, the front-end relief for exploration can be so influential that the overall expected tax take becomes negative. Prospectivity in Norway is comparatively high. Many investors anticipate a discovery chance of at least 1 in 5. This helps to explain the continuing interest in this country.

For an exploration program of $60 million, pre-tax EMVs are negative under all levels of prospectivity at a discount rate of 15 per cent. With success rates of 1 in 10 or less, pre-tax EMVs are negative with discount rates of 10 per cent, while post-tax EMVs become negative at real discount rates of 5 per cent. With a 1 in 5 success rate the post-tax EMVs are positive at a 5 per cent discount rate. The expected tax takes would often exceed 100 per cent of the expected rents.

The explorationist executing a program costing $20 million under the scenario of collapsed oil prices faces pre-tax EMVs that are negative at discount rates of 10 per cent and above when chances of success are 1 in 5, or worse. On a post-tax basis, EMVs are negative at discount rates of 5 per cent. The government again shares to a

marked extent in the exploration losses by giving immediate relief for these costs to the ongoing investor for both income tax and Special Tax.

Table 6.5
Norway (State Participation Included)
Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)	
	Pre-Tax	Post-Tax and Participation	Tax	Total
Overall Discovery Rate: 1 in 5				
0	572.8	42.6	71.2	90.4
5	245.6	12.6	79.4	93.9
10	79.8	-2.3	100.8	103.2
15	-6.1	-9.7	261.2	174.3
Overall Discovery Rate: 1 in 10				
0	276.4	19.9	70.5	90.6
5	112.3	4.8	78.6	94.8
10	28.9	-2.7	106.7	110.0
15	-14.6	-6.5	-ve	-ve
Overall Discovery Rate: 1 in 20				
0	128.2	8.5	68.9	91.1
5	45.6	0.9	76.5	97.5
10	3.4	-2.9	-	-
15	-18.9	-4.9	-ve	-ve

In sum, the Norwegian fiscal system is not sufficiently flexible to cater for the range of operating circumstances likely to be found without economic inefficiencies emerging. The reformed system of state participation, while more profit-related than the previous one, is not sufficiently sensitive to changes in profitability, whether from oil price movements or cost changes. Given that it has a high marginal rate, the system is not well enough related to economic rents. When moderate rates of depreciation and high rates of tax are combined in a tax structure, it is extremely important to ensure that the system is accurately targeted if it is to perform in an efficient manner.

Figure 6.18
Norway (Tax Only)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

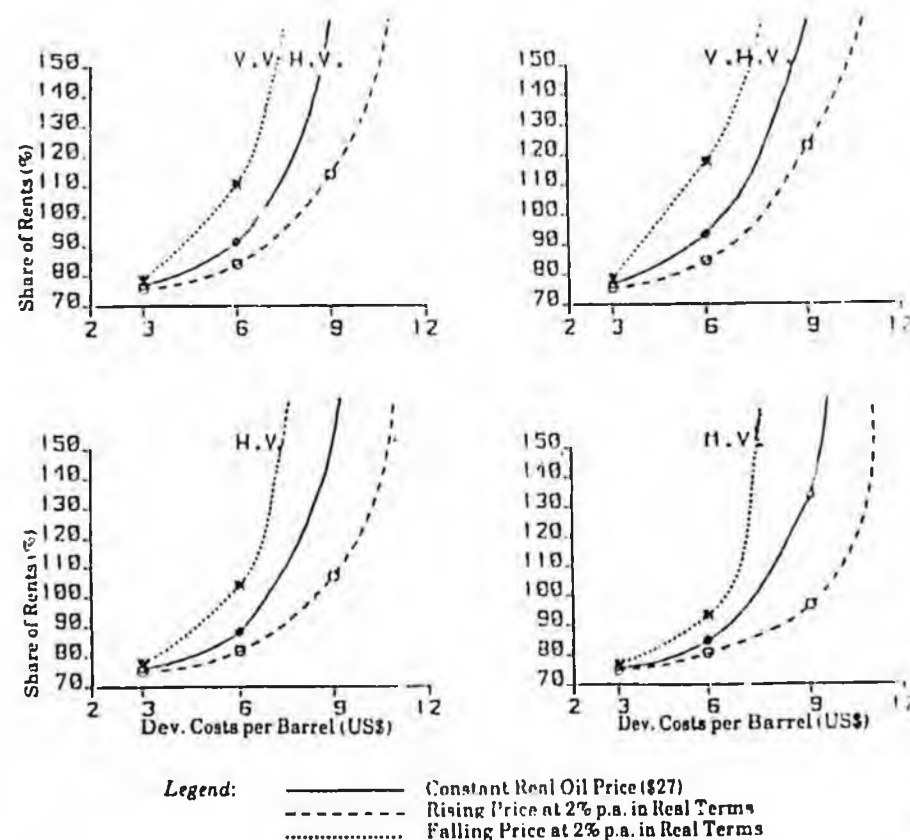
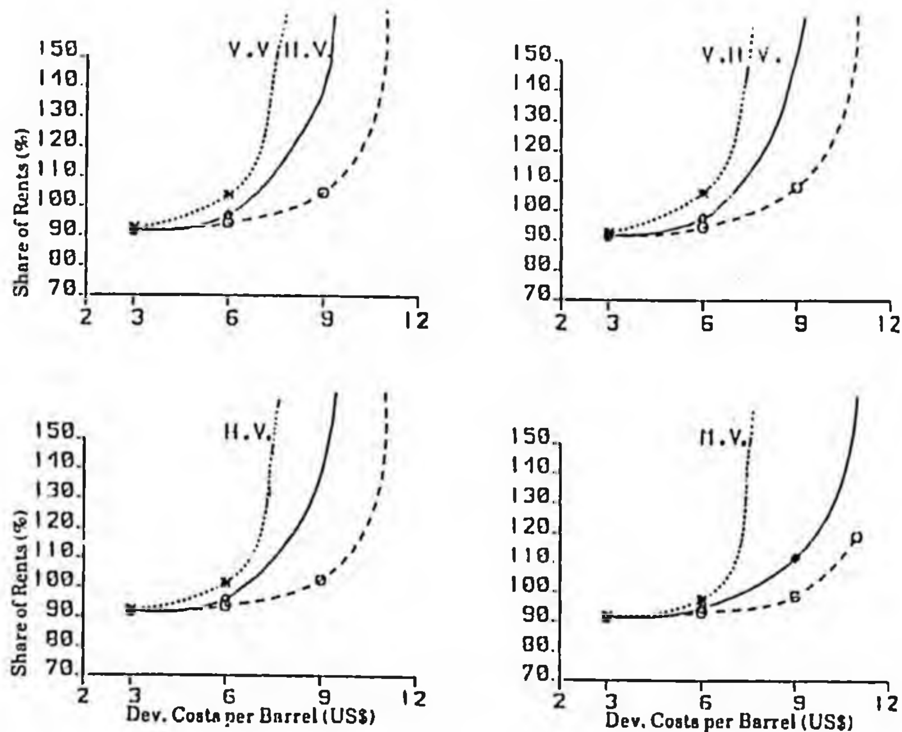
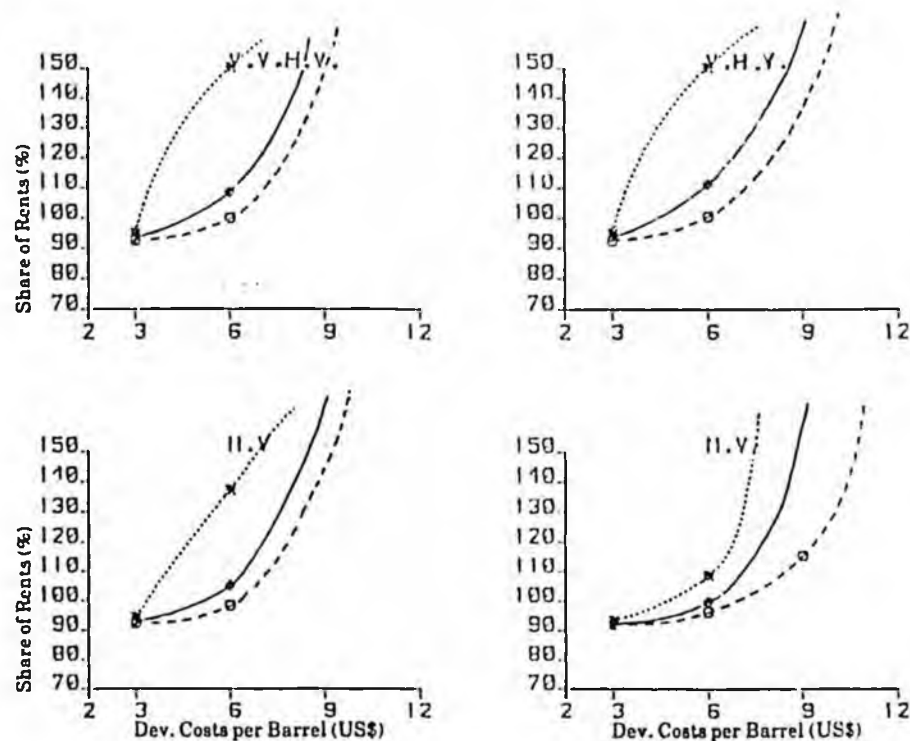


Figure 6.17
Norway (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives



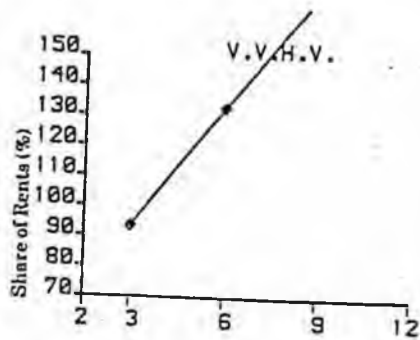
Legend: ——— Constant Real Oil Price ($27)
- - - - - - Rising Price at 2% p.a. in Real Terms
.... Falling Price at 2% p.a. in Real Terms

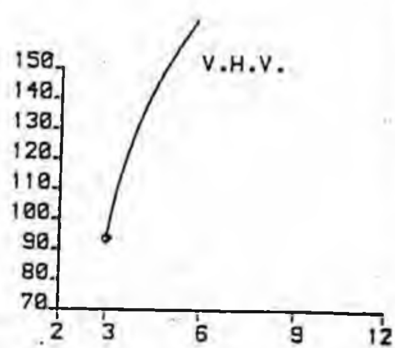
Figure 6.18
Norway (State Participation Included)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

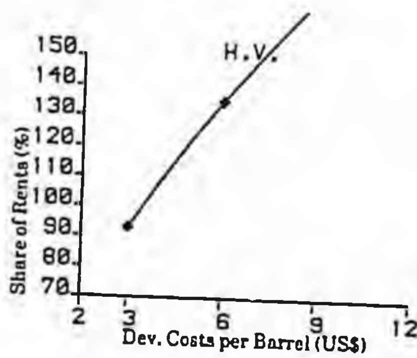


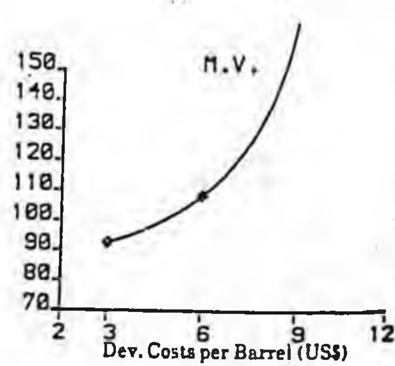
Legend: ——— Constant Real Oil Price ($27)
- - - - - - Rising Price at 2% p.a. in Real Terms
.... Falling Price at 2% p.a. in Real Terms

Figure 6.19
Norway (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price









Chapter 55. Oil and Gas Properties Production Tax.

Section
11. Oil production tax
12. Adjustment in tax rates
13. Economic limit factor
16. Gas production tax
17. Relation to other taxes
20. Payment of tax
30. Filing of statements
40. Powers of Department of Revenue
50. Incorrect returns
60. Delinquency
80. Collection and deposit of revenue
90. Refunds
110. Administration
135. Measurement
140. Definitions
150. Determination of gross value

Collateral references. — 71 Am. Jur. 2d, State and Local Taxation, §§ 218 — 220.

84 C.J.S., Taxation, §§ 404, 410.

State tax on or in respect of goods shipped in interstate commerce to consignee for sale on consignor's account without previous sale or order for purchase, 4 ALR2d 244.

Constitutional exemption from taxation as subject to legislative regulation respecting conditions of its assertion, 4 ALR2d 744.

Power of legislature to remit, release, or compromise tax claim, 28 ALR2d 1425.

When right to refund of state or local taxes accrues, within statute limiting time for applying for refund, 46 ALR2d 1350.

Legislative power to exempt from taxation property, purposes, or uses additional to those specified in constitution, 61 ALR2d 1031.

Financial hardship or inability to pay taxes as rendering inapplicable statutes denying remedy by injunction against assessment or collection of tax, 65 ALR2d 550.

Expenses and taxes deductible by lessee in computing lessor's oil and gas royalty or other return, 73 ALR2d 1056.

Sec. 43.55.010. Gross production tax. [Repealed, § 9 ch 136 SLA 1977.]

Sec. 43.55.011. Oil production tax. (a) There is levied upon the producer of oil a tax for all oil produced from each lease or property in the state, less any oil the ownership or right to which is exempt from taxation. The tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-barrel amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor determined for the oil production of the lease or property under AS 43.55.013. If the amounts calculated under (b) and (c) of this section are equal, the amount calculated under (b) of this section shall be treated as if it were the greater for purposes of this section.

(b) The percentage-of-value amount equals 12.25 percent of the gross value at the point of production of taxable oil produced on or before June 30, 1981, from the lease or property and 15 percent of the gross value at the point of production of taxable oil produced from the lease or property after June 30, 1981; except that for a lease or property coming into commercial oil production after June 30, 1981, the percentage-of-value amount equals 12.25 percent of the gross value at the point of production of taxable oil produced from the lease or prop-

erty in the first five years after the start of commercial oil production and equals 15 percent of the gross value at the point of production of taxable oil produced thereafter from the lease or property.

(c) The cents-per-barrel amount equals $0.60 per barrel of taxable old crude oil produced from the lease or property, and $0.80 per barrel for all other taxable oil produced from the lease or property, both as adjusted by AS 43.55.012.

(d) *[Repealed, § 18 ch 116 SLA 1981.]* (§ 1 ch 136 SLA 1977; am §§ 12, 18 ch 116 SLA 1981)

Cross references. — For oil and gas leasing provisions, see AS 38.05.180.

Effect of amendments. — The 1981 amendment added "on or before June 30, 1981" following "taxable oil produced" and added the language beginning "and 15 percent of the gross value" and ending "from the lease or property" in subsection (b). The amendment also repealed subsection (d) which provided for certain payments to the Alaska Native Fund in certain circumstances.

Sec. 43.55.012. Adjustment in tax rates. (a) *[Repealed, § 18 ch 116 SLA 1981.]*

(b) The cents-per-barrel amount set out in AS 43.55.011(c) as adjusted by (a) of this section applies to oil of 27 degrees API gravity. For each degree of API gravity less than 27 degrees the cents-per-barrel amount shall be reduced by $.005 and for each degree of API gravity greater than 27 degrees the cents-per-barrel amount shall be increased by $.005 except that oil above 40 degrees API gravity shall be taxed as 40 degree oil. In applying the gravity adjustment under this subsection, fractional degrees of API gravity shall be disregarded. (§ 1 ch 136 SLA 1977; am § 18 ch 116 SLA 1981)

Effect of amendments. — The 1981 amendment repealed the former subsection (a) which provided for a review of the prices received for crude oil or gas produced in Alaska and a report by the department to the governor concerning proposed changes.

Sec. 43.55.013. Economic limit factor. (a) *[Repealed, § 18 ch 116 SLA 1981.]*

(b)(1) The economic limit factor for oil production of a lease or property shall be computed according to the following formula:

(1-[PEL/TP]) exp ([460 X WD]/PEL)

where: PEL = the monthly production rate at the economic limit;
TP = the total production during the month for which the tax is to be paid;
WD = the total number of well days in the month for which the tax is to be paid; and

Where "exp" indicates that the expression following it is an exponent.

(2) If, for any month during the first 10 years following the commencement of commercial oil production of a lease or property, the

economic limit factor for oil production of that lease or property computed under (1) of this subsection is 0.7 or less, then that factor shall be applied.

(3) If, for any month during the first 10 years following the commencement of commercial oil production of a lease or property, the economic limit factor for oil production of that lease or property computed under (1) of this subsection is greater than 0.7, then the economic limit factor is one.

(4) The economic limit factor for oil production of a lease or property after the first 10 years following the commencement of commercial oil production shall be computed and applied under (1) of this subsection.

(c) The economic limit factor for gas production of a lease or property equals one minus the ratio of the monthly production rate at the economic limit to the production during the month for which the tax is to be paid.

(d) The monthly production rate at the economic limit for a lease or property is presumed to be 300 barrels times the number of well days for the lease or property during the month for which the tax is to be paid. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence of a different monthly production rate at the economic limit for the lease or property. The hearing shall be held before February 15 of the year or within six months after commencement of oil production for a lease or property. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (f) of this section into the average monthly direct operating cost determined under (e) of this section and shall be used for purposes of this section for all oil production during that calendar year from the lease or property.

(e) The average monthly direct operating cost for oil production operations of the lease or property shall be determined based on a period of not less than four consecutive months. The direct operating costs include only royalty, production supplies, purchased fuel, routine maintenance, and wages and benefits of employees working on the production operations. Additional direct operating costs not listed in this section may be included only after their inclusion in a regulation adopted by the department. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the oil production operations of the lease or property, or any other cost not directly related to the oil production operations of the lease or property.

(f) For the purpose of calculating the economic limit, the value at the point of production of oil produced from the lease or property shall be determined on the basis of the acquisition cost C.I.F. at West Coast refineries for imported oil of like quality, minus the reasonable cost of transportation between the point of production of the oil from the lease or property and those West Coast refineries.

(g) The monthly production at the economic limit for a lease or property is presumed to be 3,000 Mcf times the number of well days for the lease or property during that month for which the tax is to be paid. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence of a different monthly production rate at the economic limit for the lease or property. The hearing shall be held before February 15 of the year or within six months after commencement of gas production for a lease or property. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (i) of this section into the average monthly direct operating cost determined under (h) of this section.

(h) The average monthly direct operating cost for gas production operations of the lease or property shall be determined based on a period of not less than four consecutive months. The direct operating costs include only royalty actually and currently paid, production supplies, purchased fuel, routine maintenance, and wages and benefits of employees working on the production operations. Additional direct operating costs not listed in this section may be included only after their inclusion in a regulation adopted by the department. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the gas production operations of the lease or property, or any other cost not directly related to the gas production operations of the lease or property.

(i) For the purpose of calculating the economic limit, the value at the point of production of gas produced from the lease or property shall be determined on the basis of the volume weighted average price paid for gas of like quality and pressure in the same field.

(j) The department may aggregate two or more leases or properties (or portions of them), for purposes of determining economic limit factors under this section and applying them to AS 43.55.011 or AS 43.55.016, when economically interdependent oil or gas production operations are not confined to a single lease or property. The department may also segregate a lease or property into two or more parts, for purposes of determining economic limit factors under this section

applying them under AS 43.55.011 or AS 43.55.016, when two or more economically independent oil or gas production operations are being conducted on it, or when old crude oil is produced from the same lease or property as other oil.

(k) A determination of the monthly production rate at the economic limit for a lease or property is retroactive to January 1 of the current year. For production of a lease or property commencing after January 1, the determination of the monthly production rate at the economic limit for that lease or property made within six months after the commencement of production is retroactive to the commencement of production. (§ 1 ch 136 SLA 1977; am §§ 13 — 16, 18 ch 116 SLA 1981)

Effect of amendments. — The 1981 amendment rewrote subsection (b) and repealed former subsection (a) which read "The economic limit factor for old crude oil production of a lease or property equals 1 minus the ratio of the monthly production rate at the economic limit to the production during the month for which the tax is to be paid." The amendment also rewrote subsection (g) and in subsection (h), added "actually and currently paid" following "only royalty" in the second sentence and substituted "volume weighted average" for "highest" preceding "price paid" in subsection (i).

Sec. 43.55.015. Tax per barrel of oil. [Repealed, § 9 ch 136 SLA 1977.]

Sec. 43.55.016. Gas production tax. (a) There is levied upon the producer of gas a tax for all gas produced from each lease or property in the state, less any gas the ownership or right to which is exempt from taxation. The tax is equal to either the percentage-of-value amount calculated under (b) of this section or the cents-per-Mcf amount calculated under (c) of this section, whichever is greater, multiplied by the economic limit factor determined for gas production of the lease or property under AS 43.55.013. If the amounts calculated under (b) and (c) of this section are equal, the amount calculated under (b) of this section shall be treated as if it were the greater for purposes of this section.

(b) The percentage-of-value amount equals 10 per cent of the gross value at the point of production of the taxable gas produced from the lease or property.

(c) The cents-per-Mcf amount equals $.064 per thousand cubic feet of taxable gas produced from the lease or property as adjusted by AS 43.55.012. (§ 1 ch 136 SLA 1977)

Sec. 43.55.017. Relation to other taxes. (a) Except as provided in this chapter and in AS 43.58, the taxes imposed by this chapter are in place of all taxes now imposed by the state or any of its municipalities, and neither the state nor a municipality may impose a tax upon

(1) producing oil or gas leases;

(2) oil or gas produced or extracted in the state;

(3) the value of intangible drilling and exploration expenses.

(b) The taxes imposed by this chapter are in place of all taxes imposed by a municipality upon oil or gas in place or nonproducing oil or gas leases or properties.

(c) The taxes imposed by this chapter are not in place of the tax imposed by AS 43.57 or income taxes, franchise taxes or taxes upon the retail sale of oil or gas products. (§ 1 ch 136 SLA 1977)

NOTES TO DECISIONS

Cited in Liberati v. Bristol Bay Borough, Sup. Ct. Op. No. 1735 (File No. 3365), 584 P.2d 1115 (1978).

Sec. 43.55.018. Credit against tax. [Repealed, § 18 ch 116 SLA 1981.]

Sec. 43.55.020. **Payment of tax.** (a) The gross production tax on oil or gas shall be paid monthly. The tax is due on the 20th day of each calendar month on oil or gas produced from each lease or property during the preceding month. If the tax is not paid before the end of the month in which it becomes due, the tax becomes delinquent.

(b) The gross production tax on oil or gas shall be paid by or on behalf of the producer.

(c) *[Repealed, § 7 ch 101 SLA 1972.]*

(d) In making settlement with the royalty owner the producer may deduct the amount of the tax paid on royalty oil or gas, or may deduct royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid.

(e) Gas produced in excess of that needed for safety purposes, except gas used in the operation of a lease or property in drilling for or producing oil or gas, or for repressuring, is considered, for the purpose of this chapter and in the amount used, as gas produced from a lease or property. Gas flared beyond the amount authorized for safety by the Alaska Oil and Gas Conservation Commission under AS 31.05 is considered as gas produced, except that it is subject to a penalty equal to the tax computed under AS 43.55.016 as adjusted by AS 43.55.012 per thousand cubic feet of gas for the month in which the gas was flared.

(f) If oil or gas is sold under circumstances where the sale price does not represent the prevailing value for oil or gas of like kind, character or quality in the field or area from which the product is produced, the department may require the tax to be paid upon the basis of the value of oil or gas of the same kind, quality and character prevailing during the calendar month or production for that field or area. (§ 3 ch 7 ESLA 1955; am §§ 5 — 9 ch 101 SLA 1972; am § 7 ch 107 SLA 1976; am §§ 2, 3 ch 136 SLA 1977; am § 3 ch 158 SLA 1978)

Legislative history reports. — For report on ch. 101, SLA 1972 (FCCS HCSSB 168), see 1972 House Journal, p. 963. For report on ch. 107, SLA 1976 (SCS CSHB 583), see 1976 House Journal, p. 556.

Sec. 43.55.030. Filing of statements. (a) The tax shall be paid to the department and the person paying the tax shall file with the department at the time the tax is required to be paid a statement, under oath, on forms prescribed by or acceptable to the department, giving with other information required, the following:

(1) a description of the lease or property from which the oil or gas was produced, by name, legal description, lease number or by accounting code numbers assigned by the department;

(2) the names of the producer and the person paying the tax;

(3) the gross amount of oil or gas produced from the lease or property, and the percentage of the gross amount owned by each producer for whom the tax is paid;

(4) the total value of the oil or gas produced from the lease or property owned by each producer for whom the tax is paid; and

(5) the name of the first purchaser and the price received for the oil or gas if sold in the state.

(b) *[Repealed, § 11 ch 101 SLA 1972.]*

(c) *[Repealed, § 11 ch 101 SLA 1972.]*

(d) Reports by or on behalf of the producer are delinquent the first day following the day the tax is due. Each producer is subject to a penalty of $25 a day for each lease or property upon which the report is not filed. The penalty for failure to file a report is in addition to the penalty for delinquent taxes, and is a lien against the assets of the producer. (§ 4 ch 7 ESLA 1955; am §§ 10 — 12 ch 101 SLA 1972; am §§ 4 — 6 ch 136 SLA 1977)

Revisor's notes. — Paragraph (a)(6) was renumbered as (a)(5) in 1983 since former (a)(5) had been repealed.

Sec. 43.55.040. Powers of Department of Revenue. The department may (1) require a person engaged in production and the agent or employee of the person, and the purchaser of oil or gas, or the owner of a royalty interest in oil or gas to furnish additional information that is considered by the department as necessary to compute the amount of the tax; (2) examine the books, records, and files of such a person; (3) conduct hearings and compel the attendance of witnesses and the production of books, records, and papers of any person; and (4) make an investigation or hold an inquiry that is considered necessary to a disclosure of the facts as to (A) the amount of production from any oil or gas location, or of a company or other producer of oil or gas, and (B) the rendition of the oil and gas for taxing purposes. (§ 5 ch 7 ESLA 1955)

Sec. 43.55.050. Incorrect returns. The department may determine whether or not a return required by this chapter to be filed with it is correct. If a person makes an untrue or incorrect return of the gross production or the value of it, or fails or refuses to make a return, the department shall, under regulations prescribed by it, determine the correct amount of gross production or the value of it, and compute the tax. (§ 6 ch 7 ESLA 1955)

Sec. 43.55.060. Delinquency. When the tax provided for in this chapter becomes delinquent, it bears interest at the rate prescribed in AS 43.05.225. If any person fails to make a report required by this chapter, within the time prescribed by law for the report, the department shall examine the books, records and files of the person to determine the amount and value of the production to compute the tax, and the department shall add to the tax the cost of the examination, together with any penalties accrued. (§ 7 ch 7 ESLA 1955; am § 4 ch 58 SLA 1971; am § 13 ch 82 SLA 1982)

Effect of amendments. — The 1982 amendment substituted "rate prescribed in AS 43.05.225" for "the rate of six percent a year" at the end of the first sentence.

Sec. 43.55.070. Lien for tax. [Repealed, § 4 ch 94 SLA 1976. For current law, see AS 43.10.035.]

Sec. 43.55.080. Collection and deposit of revenue. The department shall deposit in the general fund the money collected by it under this chapter. (§ 10 ch 7 ESLA 1955; am § 14 ch 101 SLA 1972)

Sec. 43.55.090. Refunds. In case of overpayment, duplicate payment or payment made in error, the department may issue a certificate stating the facts and the amount of the refund to which the taxpayer is entitled. Upon presentation of the certificate to the Department of Administration, the Department of Administration shall issue a warrant for the refund. The refund shall be paid out of the unappropriated gross production tax in the treasury. (§ 11 ch 7 ESLA 1955)

Sec. 43.55.100. Acceptance of deductions. [Repealed, § 15 ch 101 SLA 1972.]

Sec. 43.55.110. Administration. (a) The department may adopt regulations for the purpose of making and filing reports required by this chapter and otherwise necessary to the enforcement of this chapter.

(b) The department may require a sufficient bond from every person charged with the making and filing of reports and the payment of the tax. The bond shall run to the state and shall be conditioned upon the

the regulations of the department, and for the prompt payment, by the principal on the bond, of all taxes due the state by virtue of this chapter.

(c) If reports required have not been filed, or are insufficient to furnish the information required by the department, the department shall institute, in the name of the state upon relation of the department, the necessary action or proceedings to enjoin the person from continuing operations until the reports are filed.

(d) Upon showing that the state is in danger of losing its claims or the property is being mismanaged, dissipated or concealed, a receiver shall be appointed at the suit of the state. (§ 13 ch 7 ESLA 1955)

Sec. 43.55.120 — 43.55.130. Noncompliance and false reports. [Repealed, § 46 ch 113 SLA 1980. For criminal penalties, see AS 43.05.290.]

Sec. 43.55.135. Measurement. For the purposes of this chapter, oil shall be measured in terms of a "barrel of oil" and gas shall be measured in terms of a "cubic foot of gas." (§ 16 ch 101 SLA 1972)

Sec. 43.55.140. Definitions. In this chapter

(1) "API gravity" means the specific gravity of oil measured in degrees on the American Petroleum Institute scale;

(2) "barrel of oil" means 42 United States gallons of oil of 231 cubic inches a gallon computed at a temperature of 60 degrees Fahrenheit;

(3) "cubic foot of gas" means the volume of gas contained in one cubic foot of space measured at a pressure base of 14.65 pounds per square inch absolute and a temperature base of 60 degrees Fahrenheit;

(4) "department" means the Department of Revenue;

(5) "gas" means all natural, associated or casinghead gas, all hydrocarbons produced at the wellhead not defined as oil, and all liquid hydrocarbons extracted at a gas processing plant;

(6) "gross value at the point of production" means

(A) for oil, the value of the oil at the point where it is metered or measured (by automatic custody transfer meter, tank gauge, or other method approved by the commissioner) in a condition of pipeline quality on the premises of the lease or property from which it is recovered; however, if the oil is not of pipeline quality when it is removed from the premises of the lease or property from which it is recovered, or if the oil recovered from a lease or property is not metered or measured (by automatic custody transfer meter, tank gauge, or other method approved by the commissioner) on the premises of the lease or property from which it is recovered, then the gross value at the point of production is the value of that oil at the off-premises location where the oil is first metered or measured (by automatic custody transfer meter, tank gauge, or other method approved by the commissioner) in a condition of pipeline quality;

(B) for gas recovered from or in association with oil, the value of the gas at the point where it is accurately metered or measured after separation from the oil; for gas run through a gas processing plant, the gross value at the point of production is the full consideration received by the producer for the gas if sold in an arm's length transaction or, in the absence of an arm's length transaction, is the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas, less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant from the premises upon which the oil production operation is conducted; and

(C) for gas not recovered from or in association with oil, the value of the gas at the point where it is accurately metered or measured or the value of the gas at the point of sale, if any, on the premises of the lease or property from which the gas is recovered, whichever is the higher value; for gas run through a gas processing plant, the gross value at the point of production is the full consideration received by the producer for the gas if sold in an arm's length transaction or, in the absence of an arm's length transaction, is the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas, less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant from the point where it was accurately metered or measured;

(7) "intangible drilling expenses" as defined in 26 U.S.C. 263(c) (Internal Revenue Code) as defined on January 1, 1974;

(8) "lease or property" means any right, title or interest in or the right to produce or recover oil or gas including:

(A) a mineral interest,

(B) a leasehold interest,

(C) a working interest, royalty interest, overriding royalty interest, production payment, net profit interest or any other interest in a lease, concession, joint venture or other agreement for oil and gas exploration, development or production,

(D) a working interest, royalty interest, overriding royalty interest, production payment, net profit interest or any other interest in an agreement for unitization or pooling under the provisions of 26 U.S.C. 614(b)(3) (Internal Revenue Code) as defined on January 1, 1974;

(9) "oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered by separation from gas other than at a gas processing plant;

(10) "oil production operation" means the operation by which oil is recovered from a lease or property and rendered into oil of pipeline quality, and includes any gathering done before the oil is finally rendered into oil of pipeline quality;

(11) "old crude oil" means crude oil production classified as "old crude oil" in 10 CFR Chapter II Part 212-72 on May 1, 1977, and which

(12) "ownership or right to which is exempt from taxation" means any ownership interest of the federal government or the state;

(13) "pipeline quality" means good and merchantable condition;

(14) "well days" means the number of days in which a well is operating during a month. (§ 1 ch 7 ESLA 1955; am § 17 ch 101 SLA 1972; am § 3 ch 4 FSSLA 1973; am § 4 ch 159 SLA 1975; am §§ 7, 9 ch 136 SLA 1977)

Revisor's notes. — The paragraphs were renumbered in 1983 to achieve alphabetical order and to delete repealed paragraphs.

Sec. 43.55.150. Determination of gross value. (a) For the purposes of this chapter, the gross value shall be calculated using the reasonable costs of transportation of the oil or gas. The reasonable costs of transportation shall be the actual costs, except

(1) when the parties to the transportation of oil or gas are affiliated;

(2) when the contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation;

(3) when the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

(b) If the department finds that the conditions in (a)(1), (2), and (3) of this section are present, the department shall determine the reasonable costs of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods. Transportation costs fixed by tariff rates properly on file with the Alaska Public Utilities Commission or other regulatory agency shall be considered prima facie reasonable. (§ 6 ch 107 SLA 1976; am § 92 ch 59 SLA 1982)

Effect of amendments. — The 1982 amendment substituted "Alaska Public Utilities Commission" for "Alaska Pipeline Commission" near the end of subsection (b).

Chapter 56. Oil and Gas Exploration, Production and Pipeline Transportation Property Taxes.

Section

10. Levy of tax
20. Exemptions
30. In place of other taxes
40. State Assessment Review Board
50. Per diem and expenses
60. Assessment
70. Returns
80. Investigation
90. Assessment roll
100. Assessment notice
110. Appeal to the department
120. Appeal to the State Assessment Review Board
130. Hearings of State Assessment Review Board
135. Certification
140. Supplementary assessment rolls
150. Collection and deposit
160. Interest and penalty
180. Remedy

(—) The provisions of AS 43.50.225 relating to the interest on delinquent taxes apply to the tax imposed under this chapter. (Eff. 2/27/83, Reg. 85)

Authority: AS 43.05.080 AS 43.50.100(d)
AS 43.05.220(a) AS 43.50.150
AS 43.05.225

15 AAC 50.190. DEFINITIONS. In addition to the definitions contained in AS 43.50.170, in this chapter

(1) "cigarette business" means a category of activity in the state as a manufacturer, distributor, direct-buying retailer, vending machine operator, retailer, or buyer of cigarettes;

(2) "department" means the Department of Revenue;

(3) "import or acquire" includes all manners, ways, and modes of bringing or obtaining cigarettes in the state and, in the case of a manufacturer, includes bringing cigarettes into the state for samples or storage;

(4) "Indian" means a person registered on the tribal rolls of the Indian tribe occupying an Indian reservation;

(5) "Indian reservation" means all land set aside by the United States for the exclusive use and occupancy of Indian tribes, which are recognized as Indian reservations under federal law and, as of February 27, 1983, includes only the Annette Islands Reserve set aside by the United States for the exclusive use and occupancy of Metlakatla Indian Community; and

(6) "license year" means the 12 months commencing July 1 of one calendar year and ending June 30 of the following calendar year. (Eff. 2/27/83, Reg. 85)

Authority: AS 43.05.080
AS 43.50.150
AS 43.50.170

CHAPTER 55.
OIL AND GAS PROPERTIES PRODUCTION TAX

Section

10. Monthly production rate at the economic limit
20. Well days
30. Economic limit factor for casinghead gas
40. Interim taxation of gas well gas
45. Economic limit factor for distillate or condensate
50. Gas run through a gas processing plant
60. Lease identification number
70. Flared gas penalty
80. Interest
90. Significant digits in economic limit factors
100. Average API gravity
110. Application of early development incentive credit against production tax
120. (Repealed)
150. Valuation of oil or gas
160. Sales price
165. Estimated payment of taxes
170. Prevailing value for oil
172. Prevailing value for gas
180. Choice of methods for determining reasonable cost of transportation
190. Calculation of reasonable costs oftransportation
200. Retroactive adjustments
210. Definitions
9660. (Repealed)
9670. (Repealed)
9690. (Repealed)
9694. (Repealed)
9699. (Repealed)
9700. (Repealed)

15 AAC 55.010. MONTHLY PRODUCTION RATE AT THE ECONOMIC LIMIT. (a) The presumed monthly production rate at the economic limit of 300 barrels per well day for oil production of a lease or property includes royalty and all other ownership interests in that production.

(b) When the monthly production rate at the economic limit is being determined for a lease or property by dividing the per-unit value of production into the average monthly direct operating costs, the monthly production rate at the

economic limit equals the final quotient obtained by dividing, first, the per-unit value of production into the average monthly direct operating costs other than royalty, and then dividing the first quotient by the fraction of production corresponding to all nonroyalty interests in the lease or property. If some or all of a direct operating cost is borne by a royalty interest, then with respect to that cost the royalty interest will be regarded as a nonroyalty interest for purposes of the preceding sentence.

(c) The tax on oil produced from a lease or property in commercial production after June 30, 1981, must be computed by using the rates specified in AS 43.55.011 (b) and the economic limit factor specified in AS 43.55.013 (b). "Commercial production," for purposes of this subsection, means the production of oil for purposes of sale, or other beneficial use not associated with the exploration and development of the field in which the lease or property lies, except when the sale or beneficial use is incidental to the testing of an unproved well or unproved completion interval.

(d) When the primary production from a well or wells on a lease or property is gas, the monthly production at the economic limit for that lease or property is presumed to be 3,000 Mcf per well times the number of well days for that lease or property during that month for which the tax is to be paid. The economic limit for gas production of a lease or property includes royalty and all other ownership interests in the production. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.240 by providing clear and convincing evidence that the value determined under AS 43.55.013(i) for the lease or property, when divided into the average monthly direct operating cost determined under AS 43.55.013(h) for the lease or property, produces a different amount for the monthly production at the economic limit under AS 43.55.013(g) for the lease or property. (Eff. 7/1/77, Reg. 63; am 3/26/82, Reg. 81)

Authority: AS 43.05.080 AS 43.55.013
AS 43.55.011 AS 43.55.110

15 AAC 55.020. WELL DAYS. The number of well days for a well during a month is the number of days the well is reported to the Division of Oil and Gas Conservation as having been produced during that month. The days of operation for injection wells will not be included in the determination of well days. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080
AS 43.55.110
AS 43.55.140

15 AAC 55.030. ECONOMIC LIMIT FACTOR FOR CASINGHEAD GAS. When the primary production from a well or wells on a lease or property is oil, the economic limit factor for gas produced from or in association with that oil will be calculated using the following formula:

economic limit factor = 1 - (PEL/TP)

where: PEL = the monthly production rate at the economic limit, presumed to be 300 barrels per well times the total number of well days in the month for which the tax is to be paid;

TP = the total oil production during the month for which the tax is to be paid.

(Eff. 7/1/77, Reg. 63; am 11/25/77, Reg. 64; am 3/26/82, Reg. 81)

Authority: AS 43.05.080
AS 43.55.013
AS 43.55.110

15 AAC 55.040. INTERIM TAXATION OF GAS WELL GAS. For gas produced on or after July 1, 1977, and before January 1, 1978, which is not produced from or in association with oil, payments must be made using an economic limit factor of one (1.000000). When an economic limit factor is determined for production during 1978 as required by AS 43.55.013(g), the taxpayer may apply that economic limit factor to the gas produced on or after July 1, 1977, and before January 1, 1978, and the tax paid for that gas production will be adjusted accordingly. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080 AS 43.55.016
AS 43.55.013 AS 43.55.110

15 AAC 55.045. ECONOMIC LIMIT FACTOR FOR DISTILLATE OR CONDENSATE. When the primary production of a well or wells on a lease or property is gas, the economic limit

factor for distillate or condensate recovered from that gas will be calculated using the following formula:

economic limit factor = [1 - (PEL/TP)] exp [(4.600 x WD)/PEL]

where: PEL = the monthly production rate at the economic limit, presumed to be 3,000 Mcf per well times the total number of well days in the month for which the tax is to be paid;

TP = the total gas production during the month for which the tax is to be paid;

WD = the total number of well days in the month for which the tax is to be paid; and

where "exp" means that the expression following it is an exponent. (Eff. 3/26/82, Reg. 81)

Authority: AS 43.05.080
AS 43.55.013
AS 43.55.110

15 AAC 55.050. GAS RUN THROUGH A GAS PROCESSING PLANT. For gas run through a gas processing plant, the comparison of the cents-per-Mcf amount under AS 43.55.016(c) and the percentage-of-value amount under AS 43.55.016(b) will not be made by comparing cents-per-Mcf to percentage-of-value for the residue gas separately from the extracted liquids. The percentage-of-value amount is to be based on the full consideration received by the producer for that gas in an arm's length transaction, or, in the absence of an arm's length transaction, the sum of the value of the liquids extracted from the gas at the plant and the value of the residue gas less a reasonable allowance for processing the gas at the plant and for transporting the gas to the plant. The cents-per-Mcf amount is to be based on the volume of gas delivered to the gas processing plant, minus the sum of (1) the volume of gas returned from the processing plant and used in the operation of the lease or property in drilling for or producing oil or gas, (2) the volume of gas returned from the processing plant and injected back into the reservoir for repressuring, and (3) that percentage of the gas used as fuel for the processing plant which equals the percentage of the gas delivered to the processing plant which is returned and used for either of the purposes described in (1) or (2) of this sentence. (Eff. 7/1/77, Reg. 63; am 11/25/77, Reg. 64)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.016 AS 43.55.140

15 AAC 55.060. LEASE IDENTIFICATION NUMBER. The Department of Revenue may require the person paying the tax to include an identification number on the statement filed. (Eff. 1/2/71, Reg. 36)

Authority: AS 43.55.130

15 AAC 55.070. FLARED GAS PENALTY. The cents-per-Mcf penalty under AS 43.55.020(e) for gas flared beyond the amount authorized for safety by the Department of Natural Resources under AS 31.05.170(11)(H) is in addition to the tax imposed under AS 43.55.016. The volumes flared in excess of the amounts authorized for safety purposes will be determined on the basis of the total amount so authorized for the various facilities comprising a single integrated operation. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080 AS 43.55.020
AS 43.55.016 AS 43.55.110

15 AAC 55.080. INTEREST. If for any reason it is determined that returns made and taxes paid for production during a month were incorrect and a greater tax was due for that production, interest on the amount of the additional tax due for that production will be calculated and collected at the rate of six percent a year for the time between the last day of the month after the month of production and the day the additional tax for that production is paid. (Eff. 7/1/77, Reg. 63)

Authority: AS 43.05.080
AS 43.55.060
AS 43.55.110

15 AAC 55.090. SIGNIFICANT DIGITS IN ECONOMIC LIMIT FACTORS. All economic limit factors are to be calculated to not less than six decimal places. In rounding to the sixth decimal place, rounding may be down if that which is rounded out is less than 0.0000005, but it is to be up if that which is rounded out is greater than 0.0000005; if that which is rounded

out is exactly 0.0000005, the rounding is to be up or down so that the number in the sixth decimal place is even. (Eff. 7/1/77, Reg. 63; am 11/25/77, Reg. 64)

Authority: AS 43.05.080
AS 43.55.110

15 AAC 55.100. AVERAGE API GRAVITY. The API gravity of oil produced from a lease or property will be calculated each month using the weighted average of the API gravities of the oil produced during that month from the lease or property. (Eff. 3/7/74, Reg. 49; am 6/28/74, Reg. 50; am 7/1/77, Reg. 63)

Authority: AS 43.05.080
AS 43.55.012
AS 43.55.110

15 AAC 55.110. APPLICATION OF EARLY DEVELOPMENT INCENTIVE CREDIT AGAINST PRODUCTION TAX. (a) Against the production tax each month on the oil or gas production of a lease or property, the EDIC for that lease or property as of the date of payment will be allowed as a credit, up to a maximum of 50 percent of that month's production tax on the oil or gas production of that lease or property.

(b) No EDIC for a lease or property will be allowed as a credit against interest on any delinquent production tax for that lease or property, as provided by AS 43.55.060, nor against any other penalty or fee that may be added to the production tax for that lease or property.

(c) No EDIC for a lease or property will be recognized in any adjustment in a production tax payment for that lease or property if that payment was originally made when the EDIC for that lease or property was zero.

(d) An adjustment to correct a production tax underpayment for a lease or property that was originally made when the EDIC for that lease or property was not zero will be attributed to EDIC for that lease or property, up to a maximum equal to the smallest of (1) the EDIC for that lease or property as of the date of the adjustment, (2) 50 percent of the adjustment, and (3) as much of the adjustment as possible without using in the total payment, as adjusted, more EDIC for that lease or property than there was as of the date the payment was originally made; but no EDIC will be recognized in an adjustment to correct a production tax overpayment for a lease or property that was originally made when the EDIC for that lease or property was not zero.

(e) The EDIC for a lease or property will not

be allowed as a credit against production tax on oil or gas production of another lease or property, unless they are unitized or are treated, with the approval of the director as required by 15 AAC 58.070, as a single property for both reserves tax and production tax purposes. If part or all of more than one lease or property is unitized, or if two or more leases or properties are treated as a single property for both reserves tax and production tax purposes, then the EDIC attributable to each, or to the unitized portions of each, may be aggregated to determine an EDIC for the entire unit; however, if an adjustment is made after unitization (or after the several leases or properties are treated as a single property) for a production tax payment made for a lease or property before unitization (or before the several leases or properties were treated as a single property), then reference will be made only to the separate, unaggregated EDIC of that lease or property for purposes of applying (c) and (d) of this section.

(f) No EDIC for a lease or property will be allowed as a credit against the tax levied by AS 43.57.010.

(g) To illustrate the application of EDIC against production tax, the following examples are offered (and reference is also made to the examples appearing in 15 AAC 58.120 and 15 AAC 58.140):

EXAMPLE 1

On May 31 the cumulative total of reserves tax payments made before that date for a lease is $1,000,000, while the cumulative total of EDIC allowed against production tax for that lease is $950,000. The EDIC as of May 31 for that lease is thus $50,000. The production tax on oil and gas production of that lease during April is due May 31 and is $90,000. The EDIC is greater than 50 percent of the production tax to be paid, so the credit allowed is limited to 50 percent of the payment. Payment of $45,000 is made that day and $45,000 of EDIC is allowed against the production tax that is due. The EDIC on June 1 is $5,000.

EXAMPLE 2

The initial facts are the same as for Example 1, except that this time the production tax on April production is $105,000. Now the $50,000 EDIC is not greater than 50 percent of the payment, so the entire EDIC is allowed against that payment, reducing it to $55,000. This latter sum is paid on May 31, and on June 1 the EDIC is zero.

EXAMPLE 3

Assume the same situation as in Example 2; the EDIC for the lease as of June 1 is zero. On June 30 production tax of $100,000 is due for oil and gas production during May, while a reserves tax payment of $900,000 is also due that day. Production tax payments that may be credited against the reserves tax total $890,000, so a money payment of $10,000 is made that day. As of July 1 the EDIC is $10,000 but as of June 30 it is still zero. The taxpayer miscalculates the production tax and makes a money payment of $95,000, thinking it to be full payment. On July 2 he discovers his mistake and adjusts the payment by paying the remaining $5,000. No EDIC is recognized in this adjustment, even though the EDIC is $10,000 as of July 2, because the payment being adjusted was made June 30 when the EDIC was still zero. This would still be the result if the taxpayer had overpaid the production tax by $5,000 on June 30.

EXAMPLE 4

The initial facts are the same as for Example 3, except that this time the $10,000 money payment for the reserves tax is made June 29. Now, on June 30 when the production tax payment is due, the EDIC is not zero, but $10,000. The taxpayer again miscomputes the production tax as being $95,000. The EDIC is less than 50 percent of this figure, so he applies the full $10,000 as a credit and makes a money payment of $85,000. On July 20 he discovers his mistake and makes the $5,000 adjustment. This adjustment is attributable to EDIC to the extent of the smallest of (1) the EDIC as of July 20 (in this case, zero), (2) 50 percent of the adjustment ($2,500), and (3) as much of the adjustment as possible without using more EDIC in the total payment, as adjusted, than there was as of the date (June 30) the original payment was made. In this case, the full $10,000 EDIC was used June 30 in making the original payment, and accordingly, to allow any more EDIC in the $5,000 adjustment would use more EDIC in the total payment, as adjusted, than there was when the original payment was made. Thus, both the first and third criteria are zero,

...d accordingly, no EDIC can be allowed in the adjustment. The taxpayer makes a money payment of the full $5,000.

EXAMPLE 5

On July 1 the EDIC for Blackacre is $300,000 and the EDIC for Whiteacre is $200,000. On July 31 production tax payments of $50,000 for June production are made for each property. Half of each payment is made by using EDIC for the respective properties, so that as of August 1 the EDIC for Blackacre and Whiteacre is $275,000 and $175,000, respectively. Effective August 15, all of Blackacre and Whiteacre are unitized; no other leases or properties are involved. Beginning August 15, then, the unit may be regarded as a single property having an EDIC of $450,000. On August 30 an adjustment is made to correct a $5,000 underpayment of production tax on the June production of Blackacre. To apportion this adjustment between money payment and EDIC, one must refer to Blackacre's separate EDIC. The adjustment is attributable to EDIC to the extent of the smallest of (1) the EDIC as of August 30 (in this case, $275,000), (2) 50 percent of the adjustment (here, $2,500), and (3) as much of the adjustment as possible without using more EDIC in the total payment, as adjusted, than there was on July 31 when the payment being corrected was made. In the original payment, $25,000 of EDIC was used, which, coupled with the full $5,000 of the adjustment, is less than the $300,000 EDIC as of July 31. Thus, under the third criterion, $5,000 of the adjustment could be attributed to EDIC. The smallest of the three criteria is therefore the second, and so $2,500 of the adjustment made on August 30 is accounted for by EDIC for Blackacre, and the remaining $2,500 is paid by the taxpayer. The application of Blackacre's separate EDIC in that adjustment reduces the EDIC for Blackacre to $272,500. The EDIC for Whiteacre remains $175,000, and the EDIC for purposes of the unit is $447,500.

(h) All words and phrases used in this section that are defined in 15 AAC 58.150 – 15 AAC 58.180 have the same meanings for purposes of this section as they are given by those definitions. (Eff. 12/24/75, Reg. 56)

Authority: AS 43.05.080 AS 43.55.060
AS 43.55.018 AS 43.5 .010
AS 43.58.160

15 AAC 55.120. PAYMENT AND REPORTING PROCEDURES. Repealed 9/15/82.

15 AAC 55.150. VALUATION OF OIL OR GAS. (a) Except as provided in 15 AAC 55.050, this section applies to all oil and gas produced in the state on a property or lease, whether or not the oil or gas is removed from the property or lease, less any oil or gas the ownership or right to which is exempt from state taxation.

(b) The gross value at the point of production for a producer's oil or gas equals the sales price under 15 AAC 55.160 for that oil or gas, less the producer's reasonable costs of transportation under 15 AAC 55.180 and 15 AAC 55.190 for that oil or gas from its point of production to its sales delivery point and less the producer's reasonable costs incurred downstream of the point of production for processing, conditioning and preparing gas and gas plant liquids for sale; unless

(1) subsection (c) of this section applies, in which case the gross value at the point of production for that oil or gas equals the prevailing value under 15 AAC 55.170 or 15 AAC 55.172 less the reasonable costs of transportation under 15 AAC 55.180 and 15 AAC 55.190 for that oil or gas from its point of production to its sales delivery point (or, if different, to the point where prevailing value is calculated under 15 AAC 55.170 or 15 AAC 55.172) and also less the producer's reasonable costs incurred downstream of the point of production for processing, conditioning and preparing gas and gas plant liquids for sale; or

(2) the gross value at the point of production for the producer's oil or gas would exceed the applicable maximum lawful price (if any) set by the U.S. Department of Energy, the Federal Energy Regulatory Commission, another governmental agency or a court of law (adjusted for any changes in value due to any processing, conditioning and transportation of that oil or gas occurring between its point of production and the point at which the applicable maximum lawful price is effective), in which case the gross value at the point of production equals that applicable maximum lawful price as adjusted for these changes in value.

(c) The prevailing value under 15 AAC 55.170 or 15 AAC 55.172 must be used in determining the gross value at the point of production for a producer's oil or gas if

(1) the circumstances relating to the disposition of the producer's oil or gas show fraud or an intent to evade taxes; or

(2) the sales price for that oil or gas is substantially lower (determined by analyzing the cash value of the consideration received for that oil or gas and taking into account the degree of difference between the prevailing value and the sales price for that oil or gas, the quantity of oil or gas involved in the transaction, and the duration of the transaction) than the prevailing value under 15 AAC 170 or 15 AAC 55.172 for oil or gas and one or more of the following conditions exist:

(A) the contract under which the producer's oil or gas is sold or exchanged is executed or renegotiated after December 31, 1979 and either sets a price for that oil or gas without adjustments tied to market conditions or does not provide for later renegotiation of prices at market rates;

(B) the contract sets a price which does not reasonably reflect market conditions for production from that field or area prevailing at the time the contract is executed or renegotiated; or

(C) the contract price under which the producer's oil or gas is sold or exchanged reflects an unusually weak bargaining position on the producer's part because of circumstances which the producer could reasonably have foreseen and taken steps to ameliorate or avoid.

(d) For valuation purposes, production of oil or gas does not include oil or gas

(1) used or unavoidably lost in production operations on the lease or property; or

(2) flared in amounts authorized for safety by the Alaska Oil and Gas Conservation Commission under AS 31.05.170(11)(H); or

(3) injected into a reservoir in the course o operations in the same field for purposes o repressuring or conservation.

(e) In this section, 15 AAC 55.160, and 15 AA(55.210, the terms "exchange" and "exchanged' do not include a transfer of oil by a producer to . third party at the Port of Valdez or at another por in the state for purposes of operational necessit; or convenience in what otherwise would be ; bona fide, arm's-length exchange but for the fac that at the time of the particular transfer th(producer expects to later receive a like amount o similar quality oil from that third party at th(same port. This transfer to a third party and th(later transfer from the third party will be disregarded and the oil transferred will be treated a: if it had remained in the possession of the transferring producer pending final disposition of tha oil. (Eff. 1/6/80, Reg. 73; am 5/21/81, Reg. 78

Authority: AS 43.05.080
AS 43.55.020(e) and (f
AS 43.55.110
AS 43.55.150

15 AAC 55.160. SALES PRICE. (a) The sales price for purposes of 15 AAC 55.010 — 15 AAC 55.210 for first sales of a producer's oil or gas t(one or more third parties is the cash value of th full consideration being given in receipt for tha oil or gas in those sales.

(b) If a producer's oil or gas is sold to an affiliat(of that producer (as opposed to being transferre(from one division to another within the sam corporate person), the sales price of that oil or ga for purposes of 15 AAC 55.010 — 15 AA(55.210 is the greater of

(1) the cash value of the full consideratio: given in receipt for the oil or gas so sold; and

(2) the price attributable to that sale which i entered on the producer's books in accordanc with generally accepted accounting principle: consistently applied.

(c) If a producer's oil or gas is retained by th producer or is transferred from the productio: division to another division within the same cor porate person, the sales price of that oil or gas fo purposes of 15 AAC 55.010 — 15 AAC 55.210 i the price attributable to that oil or gas which i entered on the producer's books in accordanc

generally accepted accounting principles, consistently applied.

(d) If a producer exchanges oil or gas with a third party, the sales price of that oil or gas for purposes of 15 AAC 55.010 — 15 AAC 55.210 is

(1) the price prescribed in the exchange agreement for the producer's oil or gas for purposes of settling accounts and cashing out any net exchange balances in the producer's favor (to illustrate what is meant by a net exchange balance in the producer's favor, suppose the exchange is for oil on a barrel-for-barrel basis and the producer's volume to the third party exceeds the volume received from the third party; the amount of that excess would be the net exchange balance in the producer's favor); or

(2) if there is no such price prescribed in the exchange agreement, the price attributable to the oil or gas received by the producer which is entered on the producer's books in accordance with generally accepted accounting principles, consistently applied. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080
AS 43.55.020(f)
AS 43.55.110

15 AAC 55.165. ESTIMATED PAYMENT OF TAXES. (a) Beginning with the six-month period of July through December 1984, and for each succeeding six-month period after that, the department will compute and publish an interim sales price for oil from each oil producing field or area in Alaska for each month of that six-month period. The department will publish interim sales prices for the first six months of a calendar year before August 31 of that year and will publish interim sales prices for the second six months of the calendar year before March 1 of the following year. The interim sales price will be based on the volume-weighted average sales price of all taxpayers' sales in the same market for each month as reported by the taxpayers on their production tax returns. The volume-weighted average reported sales price is an arithmetic calculation based on returns as filed and is not a determination of the prevailing value of the oil.

(b) A taxpayer will recalculate its aggregate tax liability based on the interim sales price under (a) of this section and it shall pay the difference between the reported tax liability and the recalculated tax liability for the six-month period. If the amount of taxes paid by a taxpayer exceeds the recalculated tax liability for the six-month period, then the taxpayer may treat the excess as a credit against future estimated payments. Notwithstanding 15 AAC 05.050, the department will defer action on a claim for refund of the recalculated tax until the department has made a final determination of taxes due under 15 AAC 55.

(c) A taxpayer shall file a report on a form prescribed by the department and shall, as appropriate, either pay with money or by applying a credit accrued under (b) of this section, or claim a credit for, the difference between the recalculated tax liability under this section and the reported tax liability. The report and the payment of claim of credit for the first six months of the calendar year must be filed no later than October 31 of that year, and the report and the payment or claim of credit for the second six months of the calendar year must be filed no later than April 30 of the following year. (Eff. 9/1/84, Reg. 91)

Authority: AS 43.05.080 AS 43.55.040
AS 43.55.020 AS 43.55.110
AS 43.55.030

15 AAC 55.170 PREVAILING VALUE FOR OIL. (a) For a producer's oil, the prevailing value for purposes of this chapter is the arithmetic average acquisition cost C.I.F. (at the refinery inlet in the same market in which the producer's Alaskan oil is refined) based on the sales price of like oil sold in up to three third-party, arm's-length transactions selected by the department. In this subsection, "like oil" means an oil of substantially similar quality produced in the same general area of the state and subject to the same federal price controls, if any, as the oil for which the prevailing value is to be determined.

(b) If the information under (a) of this section is not available, then the prevailing value for purposes of this chapter equals the arithmetic average acquisition cost C.I.F. (at the refinery inlet in the same market in which the producer's Alaskan oil is refined) of up to six oils selected by the department including

(1) up to three domestic oils of substantially similar quality which are sold in significant

quantities in the same market or near the same market; and

(2) up to three imported oils of substantially similar quality which are sold in significant quantities in the same market or near the same market.

(c) The respective acquisition cost C.I.F. at the refinery inlet in a market for each of the oils used in this section equals the sum of

(1) the respective official government sales price or posted price of the oil (with adjustments for differentials and surcharges) appearing in the latest Platt's Oilgram Price Report published on or before the last day of a month; plus

(2) the respective tanker transportation cost of the oil from its port of origin to ship's rail in the same market as that in which the producer's Alaskan oil is refined, to be calculated

(A) by multiplying the London Tanker Broker's average freight rate assessment ("AFRA") applicable to that voyage during that month for AFRA LR 2 (Long Range 2) oil tankers, by the most recently published Worldscale rate for that voyage; or

(B) by applying another applicable freight rate if foreign flag vessels are prohibited from transporting that oil; plus

(3) any canal tolls and expenses not included in the applicable freight rate for that voyage; plus

(4) pipeline or other carrying charges. (Eff. 1/6/80, Reg. 73; am 5/21/81, Reg. 78; am 9/1/84, Reg. 91)

Authority: AS 43.05.080
AS 43.55.020(f)
AS 43.55.110

15 AAC 55.172 PREVAILING VALUE FOR GAS. For a producer's gas, the prevailing value for purposes of this chapter is

(1) the volume-weighted average of the prices received under the terms of sales contracts for significant quantities which have been entered into or the pricing provisions of which have been amended during the tax year or the two preceding years at the sales delivery points within the same market for that production by the producer in arm's-length sales transactions for like kind character, and quality Alaskan gas produced during the month; or

(2) if the producer makes no arm's-length sales of significant quantities at the sales delivery points within the same market for like kind character, and quality Alaskan gas produced during the month, the volume-weighted average of the prices under the terms of arm's-length sales contracts for significant quantities of gas (whether between third parties or not) which were entered into or the pricing provisions of which were amended during the tax year or the two preceding years from the same field as the producer's gas (or if there are no contracts which comply with this paragraph for that field, contracts which comply with this paragraph in the nearest field to that field), with appropriate adjustments for differences, if any, in kind, character, and quality between gas sold under the reference sales contracts and the producer's gas. (Eff. 5/21/81, Reg. 78)

Authority: AS 43.05.080
AS 43.55.020(f)
AS 43.55.110

15 AAC 55.180. CHOICE OF METHODS FOR DETERMINING REASONABLE COST OF TRANSPORTATION. (a) Except as provided in (b) of this section, the reasonable cost of transportation is the actual cost of transportation as determined in 15 AAC 55.190(a) and (b).

(b) The reasonable cost of transportation is the fair market value as defined in 15 AAC 55.190(c) when all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transportation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.020(f) AS 43.55.150

15 AAC 55.190. CALCULATION OF REASONABLE COSTS OF TRANSPORTATION. (a) Reasonable costs of transportation are to be calculated from the point of production to the sales delivery point.

(b) Actual costs of transportation for purposes of 15 AAC 55.180(a) are

(1) when the transportation of oil or gas is by a regulated carrier, the tariff on file with FERC or other regulatory agency having jurisdiction that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) when transportation of oil is by a tanker or other vessel that is not owned or effectively owned by the producer of that oil

(A) for a single voyage charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the producer, plus the positioning cost, if any, borne by the producer for that vessel; or

(B) for a consecutive voyage charter or a time charter, the charter fee for that vessel, plus any voyage and port costs not included in that fee which are incurred with respect to that transportation during the term of the charter and which are borne by the producer, plus the positioning cost (amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter), if any, borne by the producer for that vessel; or

(C) for a contract of affreightment, the affreightment fee specified in that contract, plus any voyage and port costs and any positioning costs not included in that fee which are incurred with respect to that transportation during the term of the contract of affreightment and which are borne by the producer;

(3) when transportation of oil is by a tanker or other vessel that is owned or effectively owned by the producer of that oil, the producer's actual cost for that transportation, which is the sum of

(A) voyage and port costs incurred with respect to that transportation;

(B) the positioning cost, amortized over 36 months, for that vessel;

(C) depreciation of the vessel; if the vessel is actually owned by the producer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for this asset; if the vessel is effectively owned by the producer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(D) an amount, which when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this subparagraph

(i) "acquisition cost" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, including costs of improvements made after the date the vessel is placed in service by or on behalf of the producer; and

(ii) "expected life" means the period of time used to calculate depreciation under (C) of this paragraph;

(4) in the case of transportation of gas as LNG

(A) where not all of the LNG transportation facilities are subject to tariff regulations (by FERC or other agencies of the United States, state or territory or a possession of the United States or a foreign nation) and when

the producer does not have or effectively have any ownership interest in the LNG transportation facility, the amount charged to the producer for that LNG transportation;

(B) when the producer has or effectively has an ownership interest in the LNG transportation facility, the producer's actual cost for that transportation which is the sum of

(i) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the producer's gas;

(ii) the positioning cost, amortized over 36 months, for that vessel;

(iii) depreciation of the LNG transportation facility; if the facility is actually owned by the producer, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of this asset; if the LNG transportation facility is effectively owned by the producer, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(iv) an amount which, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for purposes of this subsubparagraph, "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, including costs of improvements made after the date the LNG transportation facility is placed in service by or on behalf of the producer, and "expected life" means the period of time used to calculate depreciation under (iii) of this subparagraph;

(5) when the transportation of oil or gas is by a nonregulated pipeline facility that is not owned or effectively owned by the producer of that oil or gas, the transportation fee specified in the contract plus any other costs not included in the fee with respect to that transportation which are borne by the producer;

(6) when the transportation of oil or gas is by a nonregulated pipeline facility that is owned or effectively owned by the producer of that oil or gas, an amount equal to that which would have been reported to the FERC or other regulatory agency having jurisdiction applicable to the transportation of oil or gas under (1) of this subsection, had the transportation been, in fact, under the jurisdiction of FERC or other regulatory agency for the tax reporting period.

(c) Reasonable cost of transportation under 15 AAC 55.180(b) is fair market value. Fair market value of transportation is to be determined

(1) for shipments of oil, on the basis of third-party charters (that is, time charters in which the producer does not own or effectively own the vessel) of one year or more, plus regulated transportation costs determined under (b)(1) of this section; two vessels will be considered like vessels for purposes of comparing like transportation under this chapter if the difference between them in tonnage is less than 10,000 dead-weight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels or are both CDS/ODS vessels; or

(2) for shipments of gas as LNG, on the basis of third-party charters or leases (that is, charters or leases in which the producer does not own or effectively own the LNG transportation facility in question) of three years or more which are reported to the department for like LNG transportation facilities, plus regulated transportation costs determined under (b)(1) of this section.

(d) If a producer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of this particular sale the producer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the producer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such

a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the producer were the shipper. This subsection does not apply if the producer's expected repurchase does not in fact occur.

(e) For purposes of this section, "voyage and port costs" for a vessel are costs actually incurred for fuel for the vessel while in port and at sea, stores and provisions for the vessel and her captain and crew, wages and benefits of the vessel's captain and crew, routine maintenance, port and dock fees, storage costs, demurrage, tug and pilotage fees, marine agents' fees in port, lightering, transshipment charges, customs fees and duties, regular and customary gratuities that are also legal, insurance premiums actually paid to third-party insurers, minor cargo losses or measuring differentials, loading and unloading inspection fees, Panama Canal transit fees, a reasonable management fee (to be prorated equally among vessels) for coordinating arrivals and departures into and out of ports for vessels owned, effectively owned or chartered by the producer, and other reasonable costs associated with the operation or maintenance (or both) of the vessel.

(f) A producer "effectively owns," has "effective ownership" or "effectively has an ownership interest" in a vessel, LNG transportation facility, or nonregulated pipeline facility for purposes of this section, if

(1) the vessel, LNG transportation facility, or nonregulated pipeline facility is owned by another person comprising part of a consolidated business in which the producer is also a part; or

(2) the vessel, LNG transportation facility, or nonregulated pipeline facility is the subject of a capital lease in which the producer or another person comprising part of a consolidated business in which the producer is also a part, is the lessee; or

(3) the vessel, LNG transportation facility, or nonregulated pipeline facility was built to the account of the producer (or another person comprising part of the consolidated business in which the producer is also a part), was sold and was chartered back by the producer (or another person comprising part of the consolidated business in which the producer is also a part) all in a simultaneous transaction and the vessel or LNG transportation facility is on a term charter or lease to the producer (or another person comprising part of the consolidated business in which the producer is also a part) for a period of 15 years or longer.

(g) For purposes of this chapter, the "positioning cost" for a vessel includes the costs not included in the charter for that vessel which are borne by the producer for placing that vessel into position before the first voyage under that charter or the estimated costs to be borne by the producer for delivering it up at a specified location after the last voyage under that charter, or both if the producer is obligated under the terms of the charter or contract of affreightment to bear them both.

(h) A reasonable return under (b)(3)(D) or (b)(4)(B) of this section is presumed to be that amount which yields an internal rate of return (after federal income tax) on an investment which equals two percent plus the average annual national inflation rate (measured by the GNP deflator) during

(1) the period between the time the commitment is made to construct or acquire the vessel or LNG transportation facility and the time when the vessel or LNG transportation facility has been received (or delivered) and is ready to be placed into service; or

(2) if the period in (1) of this subsection falls entirely within a calendar year, that entire calendar year.

(i) At the request of a producer or on its own motion, the department will, in its discretion, replace the return under (h) of this section with one based on the rate of return imputed to that investment or similar ones by the person owning or effectively owning the vessel or LNG transportation facility.

(j) The third-party nature of an agreement between a producer and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that producer and carrier into a

consolidated business, if, at the time they entered into that agreement, neither the producer nor the carrier exercised, directly or indirectly, any control over the business affairs of the other as the result of, or in anticipation of, their subsequent consolidation into that same consolidated business.

(k) For purposes of this section, a "pipeline facility" includes all facilities incident to the pipeline transportation of oil or gas downstream from the point of production as defined in 15 AAC 55.210. (Eff. 1/6/80, Reg. 73; am 5/21/81, Reg. 78)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.020(f) AS 43.55.150

15 AAC 55.200. RETROACTIVE ADJUSTMENTS. Retroactive adjustments in costs of transportation or sales price resulting from decisions of regulatory agencies, courts, or any other preemptive authority have a corresponding effect (increase or decrease) on the gross value at point of production as determined under this chapter, and the producer shall, within 90 days after those adjustments are made, file amended returns covering the entire period of an adjustment unless the producer has obtained a stay on such filing or payment, regardless of the pendency of appeals of those decisions. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080 AS 43.55.020
AS 43.05.280 AS 43.55.110

15 AAC 55.210. DEFINITIONS. Unless the context otherwise requires, as used in 15 AAC 55.010 – 15 AAC 55.210

(1) "area" means a geographic region or geologic province such as, but not limited to, the Cook Inlet basin or the North Slope;

(2) "FASB" means the Financial Accounting Standards Board;

(3) "FASB-13" means FASB's Statement of Financial Accounting Standards No. 13, "Accounting for Leases" (November 1976), as amended or interpreted by FASB's Statement of Financial Accounting Standards No. 17, "Accounting for Leases – Initial Direct Costs" (November 1977); FASB's Statement of Financial Accounting Standards No. 22, "Changes in the Provisions of Lease Agreements Resulting from Refundings of Tax-Exempt Debt" (June 1978); FASB's Statement of Financial Accounting Standards No. 23, "Inception of the Lease" (August 1978); FASB Interpretation No. 19, "Lessee Guarantee of the Residual Value of Leased Property" (October 1977); and FASB Interpretation No. 21, "Accounting for Leases in a Business Combination" (April 1978);

(4) "field" means that part of an area underlain by one or more overlapping, contiguous, or superimposed pools such as, but not limited to, Prudhoe Bay field or Middle Ground Shoal field;

(5) "LNG transportation facility" means any or all of the following: the LNG liquefaction plant, gathering lines to that plant, loading and unloading facilities for LNG tankers, and LNG tankers themselves;

(6) "point of production" means

(A) for oil, the automatic custody transfer meter or unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier; and in the absence of an automatic custody transfer meter or unit, the "point of production" for oil is the outlet flange of the tank gauge (or in the absence of an automatic transfer meter or a tank gauge, another mechanism or device to measure the quantity of oil that has been approved by the department for this purpose) through which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier;

(B) for gas recovered in association with oil, the meter on, or nearest (measured along the course taken by the gas) to, the lease or property from which the gas is recovered, at which meter the sales stream of gas is measured with sufficient accuracy and at appropriate temperature, pressure and other condition for purposes of sale, regardless of whether the particular gas in question is actually sold at that meter;

(C) for gas not recovered from or in association with oil, the point where it is accurately metered or measured, or if the gas is sold on the premises of the lease or

property from which it is recovered, then the point of such sale;

(7) "sales delivery point" means

(A) for a producer's oil and gas sold in a bona fide, arm's-length sale to a third party, the point of delivery specified under the terms of the contract or agreement for that sale, except in the case of a sale to which (C) of this paragraph applies;

(B) for a producer's oil not sold in a bona fide, arm's-length sale to a third party, the inlet of the refinery or comparable facility to which that oil is ultimately transported; and

(C) for a producer's gas not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the calculation of sales price of the producer's gas under 15 AAC 55.160(b):

(8) "same market" means

(A) with respect to a producer's oil refined in Alaska, the Alaskan market;

(B) with respect to a producer's oil landed on the U.S. West Coast (including Hawaii), the West Coast market or, if appropriate, the submarkets on the West Coast (i.e., Puget Sound, San Francisco Bay, the Long Beach and Los Angeles area, and Hawaii);

(C) with respect to a producer's oil landed on the U.S. Gulf Coast, the Gulf Coast market;

(D) with respect to a producer's oil landed on the U.S. East Coast, the East Coast market;

(E) with respect to a producer's oil landed in Puerto Rico or the U.S. Virgin Islands, the Puerto Rican and Virgin Island market;

(F) with respect to a producer's gas marketed in Alaska, the Alaskan market or portion of it served by gas from the same field or area as the producer's gas;

(G) with respect to a producer's gas marketed in the Lower 48, the Lower 48 market;

(H) with respect to a producer's gas marketed in a foreign country, the market in that foreign country. (Eff. 1/6/80, Reg. 73)

Authority: AS 43.05.080 AS 43.55.110
AS 43.55.020(f) AS 43.55.150

15 AAC 55.9660. NUMBER OF OIL WELLS. Repealed 7/1/77.

15 AAC 55.9670. DAILY PER WELL OIL PRODUCTION. Repealed 7/1/77.

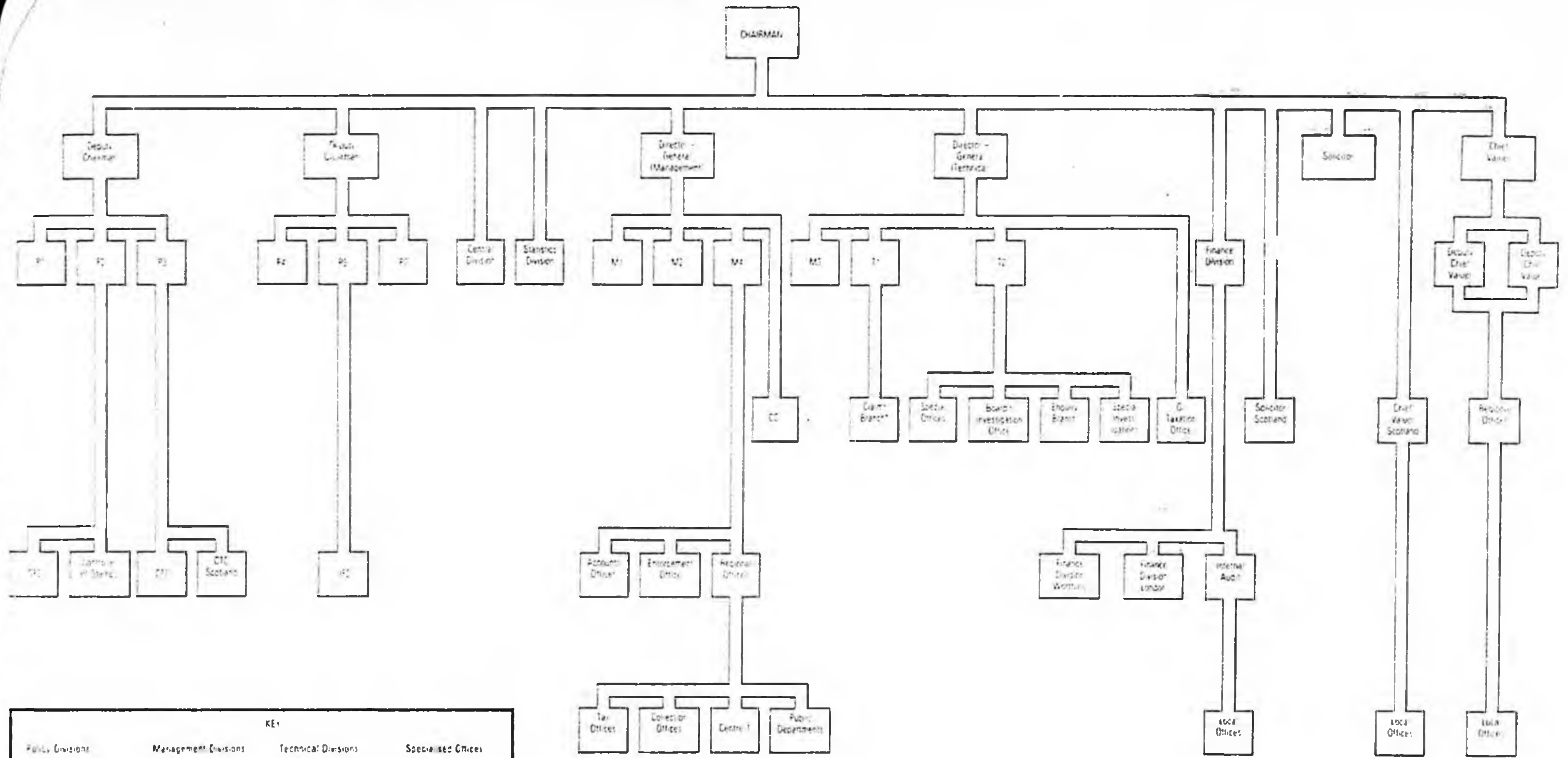
15 AAC 55.9690. SALES PRODUCTION RATIO. Repealed 3/7/74.

15 AAC 55.9694. TAX RATE CHANGES BASED ON WHOLESALE PRICE INDEX. Repealed 7/1/77.

15 AAC 55.9699. POINT OF VALUATION OF OIL. Repealed 1/6/80.

15 AAC 55.9700. DEFINITIONS. Repealed 1/6/80.

Inland Revenue–Organisation Chart



1987

services to supp. data box for est'n of market value

Inland Revenue
Petroleum Revenue Tax

Notes

1. Particulars are only required in respect of arm's length sales.

2. 'Oil' has the meaning given to it by Section 1(1) Oil Taxation Act 1975. A relevant sale is a contract for sale to which the participator, or any UK resident company which is associated with the participator, is a party as seller, buyer or otherwise, and which provides for delivery at any time within the chargeable period to which the return relates. Details of contracts which do not lead to physical delivery (bookouts) should be included.

3. The following contracts for sale are excluded -

   a. Those which have been included in the participator's return (form PRT 1) made under paragraph 2 Schedule 2 Oil Taxation Act 1975.

   b. Those which require delivery of less than 500 metric tonnes of oil.

   c. Those which relate to the sale of gas consisting mainly of methane or ethane (or a combination of them).

4. A participator who is required to submit returns on forms PRT 1 in respect of more than one oil field is required to submit only one additional return for a chargeable period.

5. Where two or more participators in an oil field are members of the same group of companies only one participator is required to make a return of 'relevant sales'. (For this purpose two companies are members of a group of companies if one is the 75% subsidiary of the other or both are 75% subsidiaries of a third company.) In such a case the name(s) of the other participator(s) on whose behalf the return is being made must be entered in the space provided on the front page.

6. In any instances where the details contained in more than one return would be identical, eg where two or more participators who are members of the same group have interests in more than one field, only one such return need contain all of the details.

   The name(s) of the other participator(s) should be entered on the front page of the complete return, and the other participator(s) should, in making his/their return(s), include a reference to the complete one.

7. It will assist processing of the return if the information about 'relevant sales' is presented so that contracts relating to various types of crude - eg Brent blend, Forties blend, Ninian blend etc, and of LPG - eg butane, propane etc - are grouped together, and so that sales are separated from purchases.

8. Where a transaction did not lead to a physical delivery specify under 'Date of delivery' the latest date for delivery under the contract, and under 'Quantity sold' the quantity of oil contracted to be sold. Enter 'B' (bookout) in the 'Notes' column.

9. Please use the 'Notes' column to identify any 'relevant sales' made under Term contracts (T); and to identify any contracts made on other than FOB and/or 30 days credit terms by stating the relevant particulars.

10. Where the price of oil is determined by reference to other prices, eg the average of specified published prices or of prices realised, please provide details on a separate sheet of the calculation of the contract price, together with a copy of the contract. If a copy of the contract has already been submitted to the Oil Taxation Office it will be sufficient to state the fact.

11. The price and the amount receivable should be stated in the currency used in the contract which will usually be US dollars. Please specify the currency where it is other than US dollars.

Oil Taxation Office
Melbourne House
Aldwych
London
WC2B 4LL
Tel: 01-438 6525

Participator's additional return

Under the provisions of Section 62(4) Finance Act 1987 you are required to complete this return and deliver it to me within two months after the end of the chargeable period. The notes on page 4 will help you to complete the return. It must contain a complete statement of all 'relevant sales' of oil (see notes 1, 2 and 3), as defined in Section 62(6) Finance Act 1987.

If you need further information please apply to this office.

When the return has been completed please ensure that the Declaration below is signed.

R M Elliss
Controller

This return is made by ______________________
Full name of participator

and is a return of my own relevant sales and those of the following participators

____

____

____

____

____

Declaration

Penalties The Finance Act 1987 provides penalties for
- failure to complete the return within the statutory period *Section 62(7)*
- fraudulent or negligent delivery of an incorrect return *Section 62(8)*

I declare that this return is correct and complete

Signed ______________________ Date ______________

Status of signatory ______________________

UK registered office address of participator making the return ______________________

____

____

______________________ Postcode ______________

PRT 1A (1987)

SHR 12/87

Crude oil

Date of delivery *see note 8*	Date of contract	Name		Type of crude *see note 7*	Quantity sold [or contracted to be sold] (barrels)	Price per barrel US $ *see notes 10 & 11*	Notes *see notes 8 and 9*
		Seller	Buyer				

Other oil

Date of delivery *see note 8*	Date of contract	Name		Type of condensate or LPG *see note 7*	Quantity sold [or contracted to be sold] (barrels*/tonnes*)	Price per barrel*/ tonne* *see notes 10 & 11*	Notes *see notes 8 and 9*
		Seller	Buyer				

** delete as appropriate*

Notes

Part A

General

Quantities of oil should be stated in the following units -

a. Crude oil: **Barrels** measured at 60°F

b. Condensates (and other hydrocarbons in a liquid state at a temperature of 15°C and at a pressure of one atmosphere (1.0132 bar)): **Tonnes**

c. Butane, propane and ethane (LPG): **Cubic** metres at 15°C and a pressure of one atmosphere

d. Ethane (gaseous) and other gaseous hydrocarbons: **Cubic metres** at 15°C and a pressure of one atmosphere.

The Oil Taxation Office may ask for a copy of the full assay and distillation analysis, or other appropriate analysis, of the oil shown in the return.

Item 1. Please state the range of API° in the form of extreme readings - eg 35° - 35.5°. In the case of LPGs (butane, propane and ethane (sold in liquid form)) the factor required is to convert cubic metres (measured at atmospheric pressure and 15°C) into metric tonnes. For ethane sold in gaseous form and other gaseous hydrocarbons please state the factor required to convert from cubic metres (measured at atmospheric pressure and 15°C) into megajoules or therms as appropriate (state which).

Item 3. State the interests of the participators in the field in the quantities of oil stated in the return. If those interests have changed during the period please state the date(s) of change and the interests before and from that (those) date(s).

Item 4. Please state here the total quantities of oil, defined as in 6. below, at the commencement of the chargeable period. It is not necessary to show the allocation between participators.

Item 5. Please state the total quantities of oil delivered or relevantly appropriated during the period, and the allocation between participators.

Item 6. 'Closing stock' is the quantity of oil won from the field which has not been disposed of and not relevantly appropriated, or which has been disposed of but not delivered, at the end of the chargeable period. Please state the total quantities and the allocation between participators.

Part B

Please state in metric tonnes each participator's share of oil (exclusive of excluded oil) won and saved from the field during the period. For this purpose 1100 cubic metres of oil which is gaseous at atmospheric pressure and at a temperature of 15°C is counted as equivalent to one metric tonne.

Part C

Notes relating to the tariff receipts allowance are printed at the head of Part C.

Penalties

The Act makes provision for penalties if you fail to submit the return within the statutory period (Schedule 2 paragraph 6), and if the return is fraudulently or negligently completed (Schedule 2 paragraph 8(3)).

Inland Revenue
Petroleum Revenue Tax

serves to reconcile estimates of prodn in PRT 1 to various participants/licensees.

Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL
Tel: 01-438 6525

Return by Responsible Person

Under the provisions of paragraph 5, Schedule 2 Oil Taxation Act 1975 you are required to complete this form and deliver it to me within one month after the end of the chargeable period.

The notes on page 4 of the form will help you to complete the return. If there is not enough space in any part of this form please continue on separate sheets which will become part of the return. If you want further information please apply to this office. Unless otherwise stated statutory references are to the Oil Taxation Act 1975.

When the return has been completed please ensure that the Declaration on page 3 is signed.

R M Elliss
Controller

Part A

Statement of oil won and saved during the chargeable period

	Crude oil		Condensates
1a. Please state the range of API° during the period			

	Butane	Propane	Ethane*
b. State the average factor(s) to convert cubic metres into metric tonnes			

	Ethane*	Other gas
c. State the average factor(s) to convert cubic metres into megajoules or therms		

see Note on item 1

PRT 2 (1987)

SHR 12/87

Part A (cont'd) Statement of oil won and saved during the chargeable period

							Total
2. Participator's names							
For official use only							
3. Field interests (%)							
4. Opening stock							
Crude oil (bbls)							
Condensates (tonnes)							
Butane ('000 m³)							
Propane (")							
Ethane (")							
Other gas (")							
5. Deliveries/Appropriations							
Crude oil (bbls)							
Condensates (tonnes)							
Butane ('000 m³)							
Propane (")							
Ethane (")							
Other gas (")							
6. 'Closing stock'							
Crude oil (bbls)							
Condensates (tonnes)							
Butane ('000 m³)							
Propane (")							
Ethane (")							
Other gas (")							

Part B Share of oil won and saved - *attach a detailed computation*

Metric tonnes						

Part C

Tariff receipts allowance

The particulars required for determination of the amounts of tariff receipts allowance (Section 9, Oil Taxtion Act 1983) are described in paragraph 1(2) of Schedule 3 to that Act. The quantity of the oil should be stated in metric tonnes. If there is more than one user field and/or more than one tariff producing asset show the quantities attributable to each separately. Distinguish between quantities of oil attributable to contracts made **before** 8 May 1982 and those made on or after that date.

Declaration

I declare that the return is correct and complete

Signed ______________________ Date ______________

Status of signatory ______________________

Full name of the Responsible Person ______________________

Registered office address ______________________

____

____

______________________ Postcode ______________

Notes on completion

Expenditure incurred after 30 June 1982 *unless alternative date under S13(1)(b)OTA 1983 applies*

Please give the following information in a supporting schedule

- the nature of the asset
- the date on which the expenditure was incurred
- the original cost, restricted as appropriate by Schedule 4, paragraph 2, OTA 1975

For dedicated mobile assets *S2 and S3 OTA 1983*

- the date of first use in connection with the field
- details of prior use and any previous relief
- details of any cessation of use *Sch 1 para 8 OTA 1983*

For non-dedicated mobile assets *S1 OTA 1983 and S4 OTA 1975*

- the date of first use in connection with the field
- the date on which its useful life is likely to end and details of any disposal *S5(7) OTA 1983*

Brought-in assets *Sch 1 para 7 OTA 1983*

Indicate in the supporting schedule(s) any brought-in assets for which information is supplied.

Apportionment

State the basis of any apportionment.

Supplement *S7(6) OTA 1983*

Where supplement has been restricted by reference to a disposal receipt, give details in a supporting schedule.

Penalties

Penalties are exigible under Paragraph 8 Schedule 2 OTA 1975 where an incorrect statement or declaration in connection with any claim is made fraudulently or negligently.

SHR 11/87

Inland Revenue
Petroleum Revenue Tax

Reference
Consecutive number of claim

Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL

Expenditure claim by Responsible Person

Use this form to claim expenditure allowable under Sections 3 and 4, Schedule 5, Oil Taxation Act 1975, and Section 3, Oil Taxation Act 1983.

The form must be completed by the Responsible Person appointed by the Board of Inland Revenue, for the oil field to which the claim relates, and should be sent with the accompanying schedules to the Oil Taxation Office at the address above. Please refer to the notes on page 4 when completing this form.

Part 1

Field ______________________

Full name of Responsible Person ______________________

Claim period from ______________ to ______________

Declaration

I declare that to the best of my knowledge and belief

- all the statements made in this claim and its supporting schedules are correct
- none of the expenditure which is the subject of this claim has been allowed on a claim under Schedules 5 or 6 of the Oil Taxation Act 1975 for this or any other oil field
- none of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) of the Oil Taxation Act 1975.

Signature of Secretary or other proper officer of the Responsible Person ______________________

Status of signatory ______________ Date ______________

UK Registered Office address ______________________

____

______________ Postcode ______________

Expenditure and supplement

Part 2 Claim under Section 3, Oil Taxation Act 1975

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement S2(9)(b)(ii) & S3(5) 2	Rate of supplement 3	Supplement claimed 4	Total claim cols. 1 + 4 5
searching for oil *S3(1)(a)*					
relevant licences *S3(1)(b)*					
ascertaining the extent, characteristics or reserves of the field *S3(1)(c)*					
winning oil *S3(1)(d)*					
measuring the quantity of oil *S3(1)(e)*					
transporting oil a. tariff payments *S3(1)(f)*					
b. other expenditure					
initial treatment or initial storage *S3(1)(g)*					
disposing of oil crude *S3(1)(h)*					
closing down the field *S3(1)(i)*					
statutory redundancy payments less recoverable rebates *S3(2)*					
Total expenditure and supplement claimed £					

Part 3 Claim for long term assets

Enter below the total amount(s) claimed and attach supporting schedules. For associated and remote associated assets, please state on the schedule: a. the asset with which it is associated and b. the name of any person paying consideration for sharing field assets. Assets no longer in use for the principal field are to be identified with supporting information.

See Schedule 1, paragraphs 1-3, Oil Taxation Act 1983

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement S2(9)(b)(ii) & S3(5) 2	Rate of supplement 3	Supplement claimed 4	Total claim cols. 1 + 4 5
non mobile assets *S3, OTA 1983*					
dedicated mobile assets *S2, S3, OTA 1983*					
non dedicated mobile assets *S4, OTA 1975. S1, OTA 1983*					
Total claim for long term assets £					

Part 4 Summary

Total claim under Section 3, OTA 1975 *Part 2, column 5* ____________

Total claim for long term assets *Part 3, column 5* ____________

Total expenditure and supplement claimed £ ____________

Part 5 Excess allowances for earlier periods *S4(9),S4(10),OTA 1975*

Participator	Share

Total of excess allowances for earlier periods £ ____________

Part 6 Participators' shares in expenditure and supplement

Participator	Interest in field (%)	Amount of expenditure	Amount of supplement	Share of expenditure and supplement *Sch 5 para 2(4)(b)*
Total claimed £				

Inland Revenue
Petroleum Revenue Tax

Reference
Consecutive number of claim

Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL

Expenditure claim by Participator

Use this form to claim expenditure allowable under Sections 3 and 4 and Schedule 6, Oil Taxation Act 1975, and Section 3, Oil Taxation Act 1983. The participator making the claim should complete and send it with accompanying schedules to the Oil Taxation Office at the address above.

Part 1 Field ______________________

Full name of Participator ______________________

Claim period from ______________________ to ______________________

Notes on completion

Long term assets

Expenditure incurred after 30 June 1982 unless alternative date under S13(1)(b)OTA 1983 applies

Please give the following information in a supporting schedule

- the nature of the asset
- the date on which the expenditure was incurred
- the original cost, restricted as appropriate by Schedule 4, paragraph 2, OTA 1975

For dedicated mobile assets (S2 and S3 OTA 1983)

- the date of first use in connection with the field
- details of prior use and any previous relief
- details of any cessation of use (Sch 1 para 8 OTA 1983)

For non-dedicated mobile assets (S1 OTA 1983 and S4 OTA 1975)

- the date of first use in connection with the field
- the date on which its useful life is likely to end and details of any disposal (S5(7)OTA 1983)

Brought-in assets (Sch 1 para 7 OTA 1983) Indicate in the supporting schedule(s) any brought-in assets for which information is supplied.

Apportionment State the basis of any apportionment.

Supplement (S7(6) OTA 1983) Where supplement has been restricted by reference to a disposal receipt, give details in a supporting schedule.

Penalties

Penalties are exigible under Paragraph 8 Schedule 2 OTA 1975 where an incorrect statement or declaration in connection with any claim is made fraudulently or negligently.

Declaration

I declare that to the best of my knowledge and belief

- all the statements made in this claim and its supporting schedules are correct
- none of the expenditure which is the subject of this claim has been allowed on a claim under Schedules 5, 6 and 7 of the Oil Taxation Act 1975 for this or any other oil field
- none of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) of the Oil Taxation Act 1975.

Signature of Secretary or other proper officer of the Participator ______________________

Status of signatory ______________________ Date ______________________

UK Registered Office address ______________________

______________________ Postcode ______________________

Expenditure and supplement

Part 2 Claim under Section 3, Oil Taxation Act 1975

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement *S2(9)(b)(ii) & S3(5)* 2	Rate of supplement 3	Supplement claimed 4	Total claim *cols 1 - 4* 5
searching for oil *S3(1)(a)*					
relevant licences *S3(1)(b)*					
ascertaining the extent, characteristics or reserves of the field *S3(1)(c)*					
winning oil *S3(1)(d)*					
measuring the quantity of oil *S3(1)(e)*					
transporting oil *S3(1)(f)* a. tariff payments					
b. other expenditure					
initial treatment or initial storage *S3(1)(g)*					
disposing of oil crude *S3(1)(h)*					
closing down the field *S3(1)(i)*					
statutory redundancy payments less recoverable rebates *S3(2)*					
Total expenditure and supplement claimed £					

Part 3 Claim for long term assets

Enter below the total amount(s) claimed and attach supporting schedules. For associated and remote associated assets, please state on the schedule: a. the asset with which it is associated and b. the name of any person paying consideration for sharing field assets. Assets no longer in use for the principal field are to be identified with supporting information.

See Schedule 1, paragraphs 1-3, Oil Taxation Act 1983

Expenditure on:	Amount of expenditure 1	Amount qualifying for supplement *S2(9)(b)(ii) & S3(5)* 2	Rate of supplement 3	Supplement claimed 4	Total claim *cols 1 - 4* 5
non mobile assets *S3, OTA 1983*					
dedicated mobile assets *S2, S3, OTA 1983*					
non dedicated mobile assets *S4, OTA 1975. S1, OTA 1983*					
Total claim for long term assets £					

Part 4 Summary

Total claim under Section 3, OTA 1975 *Part 2, column 5* ____

Total claim for long term assets *Part 3, column 5* ____

Total expenditure and supplement claimed £ ____

Part 5 Excess allowances for earlier periods *Section 4(9) and Section 4(10) OTA 1975* £ ____

Part C Complete this part if there has been a previous CFA election, including a previous election by an associated company in respect of any amount shown in Part A column 5

Line	Expenditure in respect of which previous CFA election(s) made. Repeat amount shown at corresponding line number in Part A column 5	Maximum available for CFA elections (10% of Part C column 1)	Date(s) of previous CFA election(s)	Name of company making previous CFA election(s)	Previous elected amount(s) (State total)	Elected amount this election (Part A column 7)	Aggregate of elected amounts under all CFA elections now made (Part C columns 5 & 6)
	1	2	3	4	5	6	7
	£	£			£	£	£
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

Inland Revenue
Petroleum Revenue Tax

/

Oil Taxation Office
Melbourne House
Aldwych
London
WC2B 4LL

Tel. 01-438 6525

Cross-Field Allowance
Election under Section 65 Finance Act 1987

Full name of participator in receiving field(s) ______________________

Field of origin ______________________

Receiving field(s) 1. ______________________

2. ______________________

3. ______________________

The participator in the receiving field(s) should complete this form.

The statutory requirements are set out in Section 65 and Schedule 14 Finance Act 1987 and all references are to this Act unless otherwise stated.

If there is not enough space to enter all the required details please set them out on a separate sheet which will form part of this election.

An election is irrevocable.

Please read the enclosed notes before completing this election form.

Election

I elect that the amount(s) shown in Part A column 7 (in each case not exceeding 10 per cent of the expenditure specified in Part A column 5) shall be allowable in accordance with Section 65 and Schedule 14 Finance Act 1987 in respect of the receiving field(s) shown above.

Signature of Secretary or other proper officer of the participator ______________________

Status of signatory ______________________ Date ____________

UK registered office address ______________________

____

____

______________________ Postcode ____________

Part A Enter details of the claims and final decisions as to supplement giving rise to each elected amount shown in column 7

Field of origin ______________________

Full name of participator in field of origin ______________________

	Date of claim	Schedule of claim	Claim no.	Date of final decision as to supplement - para 2(2) Schedule 14	Total amount of expenditure allowed as qualifying for supplement (excluding expenditure falling within S5A(1) OTA 1975) in the decision in column 4	Has there been a previous election in respect of the amount in column 5? If 'Yes' see Part C	Elected amount allowable in respect of the receiving field(s) and to be disregarded in the field of origin - S65(1) and (5)	Supplement to be disregarded in the field of origin as a result of the CFA election
	1	2	3	4	5	6	7	8
1					£		£	£
2								
3								
4								
5								
6								
7								
8								
9								
10								
				Total				

Part B If more than one receiving field is shown on the front page complete Part B to show the apportionment between the receiving fields of each elected amount shown in Part A column 7 - para 1(2)(d) Schedule 14

	Elected amount Repeat amount shown at corresponding line number in Part A column 7	Apportionment of elected amount between receiving fields		
		Name of field ______ Amount apportioned to field	Name of field ______ Amount apportioned to field	Name of field ______ Amount apportioned to field
	£	£	£	£
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
Total				

Notes on completion

1. Complete Part A in all cases. Complete Part B if more than one receiving field is shown on the front page of this form. Complete Part C if there has been a previous election in respect of any of the expenditure in Part A column 5.

2. An election may be made in respect of expenditure incurred on or after 17 March 1987 by the participator making the election or, if that participator is a body corporate, by an associated company in connection with a relevant new field (the field of origin) if, in relation to that field the expenditure is allowable under Section 3 or Section 4 Oil Taxation Act 1975 or Section 3 Oil Taxation Act 1983, has been allowed as qualifying for supplement, and is not expenditure falling within Section 5A(1) Oil Taxation Act 1975 [exploration and appraisal expenditure] - Section 65(1) and (2).

3. No election may be made in respect of an amount of expenditure until a final decision as to supplement has been made on a claim in respect of that amount under Schedule 5 or 6 Oil Taxation Act 1975 - para 2(1) Schedule 14.

4. A participator may not make an election in respect of expenditure incurred before the date which is his qualifying date (Section 113 Finance Act 1984) in relation to a receiving field unless that date falls before the end of the first chargeable period in relation to the receiving field - Section 65(3).

5. Certain of the terms used in this form are defined by the statutory provisions listed below -

associated company	para 10 Schedule 14
elected amount	para 1(2)(a) Schedule 14
final decision as to supplement ...	para 2(2) Schedule 14
field of origin, receiving field... ...	Section 65(1)
relevant new field	para 8 Schedule 14

6. The time limits for making an election are set out in paragraphs 2 and 3 of Schedule 14.

NOTES ON COMPLETION

1. All statutory references on this form relate to the Oil Taxation Act 1975, unless otherwise indicated.

2. The details given in Parts 2 and 3 should provide full particulars of the amounts claimed including—
   (a) the blocks to which each item of expenditure relates;
   (b) details of any expenditure claimed which was incurred jointly with other persons including a description of the basis on which such expenditure has been apportioned;
   (c) whether the whole or any part of the licence covering the blocks mentioned under (a) has been disposed of or surrendered and the extent and circumstances of any such disposal;
   (d) any restriction required under Schedule 4, paragraph 2.

3. Where any expenditure claimed represents only a part of the total abortive exploration expenditure incurred in the calendar year in question this should be indicated and cross references made to any other claims for expenditure incurred in the same year.

4. Details should be given in Part 2 of the nature of the connection between the person incurring any expenditure claimed in B and the participator.

5. Separate details should be given in Part 3 for each asset included in the claim.

6. Where any qualifying receipts arise under S.5(6), which have been included in form PRT 1, reference should be made to these in completing Parts 2 and 3.

7. Where it has been necessary to apportion any item of expenditure full particulars of the basis on which the apportionment has been made should be included.

8. Details should be provided in a separate schedule of any asset which has been the subject of an allowance (computed under Section 5(2)) in any previous claims under Schedule 7, and which has since been disposed of.

Dd 8392960 7/83 500 384 MPC

Ref. No.

Oil Taxation Office
Inland Revenue
Melbourne House
Aldwych
LONDON WC2B 4LL

SCHEDULE 7, OIL TAXATION ACT 1975

Claim by a Participator in an Oil Field for expenditure to be allowed under Section 5 Oil Taxation Act 1975

Abortive exploration expenditure incurred before 16 March 1983

This form should be completed by the Participator making the claim and sent with any accompanying Schedules to the Oil Taxation Office at the above address.

PART 1

Field for which claim is to be made ....

....

Full name of participator ....

....

DECLARATION

I declare that to the best of my knowledge and belief:

(a) all the statements made in this claim and its supporting schedules are correct;

(b) the expenditure which is the subject of this claim has not been allowed and is unlikely to become allowable on a claim under Schedules 5 or 6 or any other claim under Schedule 7 of the Oil Taxation Act 1975 for this or any other field;

(c) none of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) as modified by Section 5(4) of the Oil Taxation Act 1975;

(d) all the expenditure claimed has been incurred wholly and exclusively for the purpose of searching for oil in the United Kingdom, the territorial sea thereof or a designated area and is not and is unlikely to become allowable under Section 3 or 4 for any oil field.

Signature of secretary or other proper officer of the participator ....

Status of signatory .... Date ....198......

U.K. Registered Office address ....

.... Postcode ....

PRT 60 (1983)

PART 2 — CLAIM FOR ABORTIVE EXPLORATION EXPENDITURE OTHER THAN EXPENDITURE ON ASSETS WITH A USEFUL LIFE OF MORE THAN 12 MONTHS

		Description of expenditure	Date incurred	Amount
A	Expenditure incurred by the Participator			£
B	Expenditure incurred by a company associated with the Participator in respect of the expenditure for the purposes of Section 5(7)(c)			
TOTAL EXPENDITURE CLAIMED				

PART 3 — CLAIM FOR ABORTIVE EXPLORATION EXPENDITURE ON ASSETS WITH A USEFUL LIFE OF MORE THAN 12 MONTHS

Description of asset	Cost	Date expenditure incurred on acquiring the asset	Expected or actual useful life from date of acquisition	Dates between which asset was used for abortive exploration	Expenditure claimed
	£				£

Note

Please ensure that if an asset for which a claim has been made in this or any previous claim has been sold, details are included on form PRT 1 in accordance with Paragraphs 11 & 12 Schedule 8 Finance Act 1983.

Notes on completion

1. All statutory references on this form are to the Oil Taxation Act 1975 as amended by Finance Acts 1983 and 1985, except where otherwise shown.

2. The details given in Parts 2 and 3 should provide full particulars of the amounts claimed including -
   a. the licence and block numbers to which each item of expenditure relates and the percentage interest in each block held by the participator or the associated company incurring the expenditure
   b. details of any expenditure claimed which was incurred jointly with other persons including a description of the basis on which such expenditure has been apportioned, showing separately operator's and participator's costs
   c. any restriction required under Schedule 4 Paragraph 2
   d. in the case of a claim under Section 5A(2)(d) details regarding the expiry, determination, revocation or surrender of the licensed area in respect of which the expenditure is claimed.

3. Details should be given in Part 2 of the nature of the connection between the participator and the person incurring any expenditure claimed, if other than the participator.

4. Separate details should be given in Part 3 for each asset included in the claim.

5. a. Where any expenditure has been reduced by the receipt of any sums under Section 5(6) details of the receipts should be separately identified in Parts 2 and 3.
   b. Receipts from the disposal of oil won in the course of operations should be distinguished. Where a market value was necessary under Section 5A (5B) the claim should be noted accordingly.
   c. Where any qualifying receipts arise under Section 5(6) which have been included in form PRT 1, reference should be made to these in completing Parts 2 and 3 (Part III Schedule 8 Finance Act 1983).

6. Where it has been necessary to apportion any item of expenditure full particulars of the basis on which the apportionment has been made should be included.

7. Where a notice of a proposed field determination has been given (Schedule 1 Paragraph 2 (a)) the area proposed is treated, for the purposes of claims under Section 5A, as having become a field when the notice was given. However expenditure may be claimed in respect of an area which was comprised within a notice of proposed determination, but which was subseqently not covered by the final determination.

8. In connection with item c. of the declaration on page 1, Section 5A(2) was amended by Section 90(2) Finance Act 1985 which introduced a territorial restriction. For expenditure incurred on or after 1 April 1986 the qualifying area of exploration and appraisal is restricted to the territorial sea of the United Kingdom or a designated area.

9. No relief is available for exploration and appraisal expenditure incurred before the participator's qualifying date in relation to a field. See Section 113 Finance Act 1984.

10. Penalties are exigible under Paragraph 8 Schedule 2 where an incorrect statement or declaration in connection with any claim is made fraudulently or negligently.

Inland Revenue
Petroleum Revenue Tax

Reference	
Consecutive number of claim	

Oil Taxation Office
Melbourne House
Aldwych
LONDON
WC2B 4LL

Exploration and appraisal expenditure
Schedule 7, Oil Taxation Act 1975

Claim by a participator in an oil field for expenditure to be allowed under Section 5A Oil Taxation Act 1975

Use this form only for claims for expenditure incurred after 15 March 1983. The participator making the claim should complete and send it with any accompanying schedules to the Oil Taxation Office at the above address. Please refer to the notes on page 4 when completing this form.

Part 1

Field for which claim is made ______________________

Full name of participator ______________________

____

Declaration

I declare that to the best of my knowledge and belief -

a. All the statements made in this claim and supporting schedules are correct.

b. None of the expenditure when incurred related to a field in respect of any part of which consent for development had been granted, or a programme of development had been served on the licensees, by the Secretary of State for Energy.

c. All the expenditure claimed has been incurred wholly and exclusively for one or more of the purposes specified in Section 5A(2) Oil Taxation Act 1975.

d. None of the expenditure claimed is of a type for which an allowance is prohibited by Section 3(4) as modified by Section 5(4) Oil Taxation Act 1975.

e. None of the expenditure has been allowed under Schedules 5, 6 or 7, Oil Taxation Act 1975 for this or any other oil field.

f. Any expenditure claimed which has given rise to the receipt of any sum at the date of the claim has been reduced by the receipt in accordance with Section 5(6) as applied and amended by Section 5A(4)-(5C) Oil Taxation Act 1975.

Signature of Secretary or other proper officer of participator ______________________

Status of signatory ______________________ Date __________

UK Registered Office address ______________________

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______________________ Postcode __________

PRT 60A (1987)

MCR 392088/1/8993323 550 4/87 L

Part 2 Claim for exploration and appraisal expenditure other than expenditure on assets with a useful life of more than 12 months

Expenditure incurred by the participator or a company associated with him in respect of that expenditure

Type of expenditure	Description of expenditure - see note 2	Date incurred	Amount
For the purpose of searching for oil *S.5A (2) (a)*			£
For the purpose of ascertaining the extent or characteristics *S.5A (2) (b)*			
For the purpose of ascertaining what are reserves *S.5A (2) (c)*			
For the purpose of making licence payments described in *S.5A (3) S.5A (2) (d)*			
		Total claimed £	

Part 3 Claim for exploration and appraisal expenditure on assets with a useful life of more than 12 months

Description of asset	Cost	Date expenditure incurred on acquiring the asset	Expected or actual useful life from date of acquisition	Dates between which asset was used for exploration or appraisal	Blocks and licence numbers of areas in which asset used	Expenditure claimed
	£					£

Please note that if an asset for which a claim has been made in this or in any previous claim, has been sold, details are to be included on form PRT 1 in accordance with Paragraphs 11 and 12 Schedule 8 Finance Act 1983.

Total claimed £ ____________

Part 4 Summary

Total of Part 2 £ ____________

Total of Part 3 £ ____________

Total expenditure claimed £ ____________