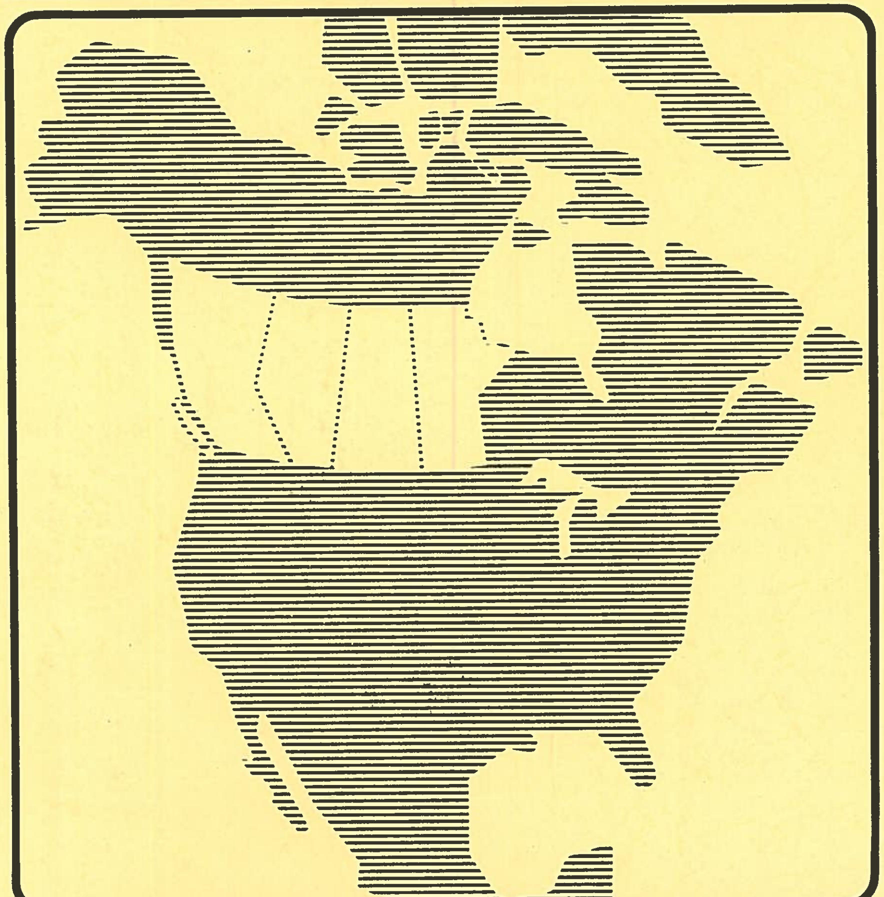
Oil and Gas Fiscal Regimes of the Western Canadian Provinces



Alberta
ENERGY
Projects and Supply Development Division
Conventional Oil, Gas and Coal Branch

OIL AND GAS FISCAL REGIMES OF THE

WESTERN CANADIAN PROVINCES

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SUMMARY

This report compares the fiscal regimes in British Columbia, Alberta, Saskatchewan and Manitoba. Since 1985, federal and provincial governments have made numerous fiscal changes, many in response to the drop in world oil prices. The more significant changes include:

- Reducing oil and gas royalties in Alberta.
- Enhancing Alberta's crude oil royalty holiday program.
- Introducing enhanced oil recovery relief in Saskatchewan.
- Introducing price-sensitive oil and gas royalties in Saskatchewan.
- Introducing natural gas royalty holidays in B.C.
- Removing the federal Petroleum and Gas Revenue Tax.
- Phased-in reduction of federal corporate taxes.
- Introducing federal exploration and development drilling incentive programs (CEDIP and CEIP).
- Introducing the Saskatchewan Resource Credit, which reduces royalties by 1%.
- Reducing the B.C. corporate tax rate to 14%.
- Introducing a provincial corporate tax holiday in Manitoba for new companies.

The new fiscal policies generally have reflected governments' willingness to forego revenues in an effort to aid the oil and gas industry. Notable exceptions to this trend have been the introduction of B.C.'s minimum gas royalty rate of 15%, the federal government's phased elimination of investment tax credits by 1989, the introduction of a 3% federal surtax, the establishment of a freehold tax on natural gas in Saskatchewan, a 1% hike in the Saskatchewan corporate tax rate and a 4% hike in the Alberta corporate tax rate. The federal government has also begun the tax reform process, the full effects of which have yet to be realized. In this document, the existing corporate tax regime is described.

A comparison of fiscal regimes must recognize the differing scale and nature of oil and gas operations among the four provinces. Alberta accounts for 80-90% of Canada's oil and gas production, while B.C., Saskatchewan and Manitoba are much smaller producers.

This comparison of fiscal regimes does not take into account variations in exploration, drilling and development costs or the variation in the frequency and size of hydrocarbon discoveries in each jurisdiction. Play economics differ for each province and would have to be taken into account to definitively compare the attractiveness of each province's oil and gas prospects.

Except where otherwise noted, all dollars are expressed in Canadian currency.

1. CROWN ROYALTIES
1.1 Conventional Crude Oil

B.C.

R% = Royalty rate
Q = Production (m^3/month)

R% = $[Q^2*100]/[K*Q]$, when $Q \leq C$
R% = $\{[A+B*(Q-C)]*100\}/Q$, when $Q > C$

Old Oil (pre-November, 1975)

K = 792
A = 11.4

B = Percent of incremental production
= 0.4

C = Production threshold for royalty calculation
= 95 m^3/month

New Oil (post-October, 1975)

K = 1 058
A = 23.9

B = Percent of incremental production
= 0.3

C = Production threshold for royalty calculation
= 159 m^3/month

ALBERTA

R% = Royalty rate
Q = Production (m^3/month)

R% = $\{S+kS[(A-B)/A]*100\}/Q$

where:

S = $Q^2/1271.28$
when $Q \leq 190.7$ m^3/month (1 200 bopm)

S = $[(Q-190.7)/4]+28.6$
when $Q \geq 190.7$ m^3/month (1 200 bopm)

A = Par Price = Average wellhead price ($/$m^3$)

B = Select Price = $40.90/$m^3$ ($6.50/b)

k = $\{[(r\%*572.07)/123.95]-1\}/[(A-B)/A]$

r% = Royalty intent at a well reference rate of
572.07 m^3 (3 600 bopm)

Old Oil (pre-April, 1974)

r% = $\{[0.2167*B]+[0.4*(A-B)]\}/A$

New Oil (post-March, 1974)

r% = $\{[0.2167*B]+[0.27*(A-B)]\}/A$
when $A \leq$ $188.80/$m^3$ ($30/b)

r% = $\{[0.2167*B]+[0.27*(188.80-B)]$
$+[0.3*(A-188.80)]\}/A$
when $A >$ $188.80/$m^3$ ($30/b)

1.1 Conventional Crude Oil (con't)

MANITOBA

R% = Royalty rate
P = Production (m^3/month)

R% = (S*C)/P

where:

S = Base Crown royalty

S = $(P)^2/265$, when $P \leq 50$ m^3/month

S = 9.43 + [0.45*(P-50)], when P > 50 m^3/month

C = 1.0 for old oil (pre-April 1, 1974)
= 0.55 for new oil (post-April 1, 1974)

SASKATCHEWAN

R% = Royalty rate
MOP = Production (m^3/month)

R% = {K-[X/MOP]} – (SRC) to a minimum of 0%

where:

X = K*23.08

A = Average wellhead price of non-heavy oil ($/$m^3$)

B = Average wellhead price of heavy oil ($/$m^3$)

SRC = One percentage point

Old Oil (pre-1974)

K = 26 + {32.5*[(A-50)/A]}

New Oil (post-1973)

K = 19.5 + {26*[(A-50)/A]} for non-heavy oil

K = 13 + {19.5*[(B-50)/B]} for heavy oil

Heavy oil is defined as oil produced from designated heavy oil areas.
All heavy oil is given new oil status.

1.1 Conventional Crude Oil (cont'd)

B.C.

Objective:

To take a royalty that is sensitive to well productivity and vintage.

Old oil

to take 40% of incremental production above 95 m^3/month as a percentage of total production.

New oil

to take 30% of incremental production above 159 m^3/month as a percentage of total production.

Low productivity wells

old oil wells producing at less than 95 m^3/month (600 bopm), and new oil wells producing at less than 159 m^3/month (1 000 bopm) benefit from lower royalty rates.

ALBERTA

Objective:

To take a royalty that is sensitive to well productivity, and crude oil price and vintage.

Old Oil

To take a royalty of 21 2/3% of the first \$40.90/m^3 (\$6.50/b) of the price, and 40% of the price in excess of \$40.90/m^3 at a well reference rate of 572 m^3/month (3 600 bopm).

New Oil

To take a royalty of 21 2/3% of the first \$40.90/m^3 of the price, 27% of the price between \$40.90 and \$188.80/m^3 (\$30/b), and to take 30% of the price above \$188.80/m^3 at a well reference rate of 572 m^3/month (3 600 bopm).

Low Productivity Wells

Wells producing at rates of less than 191 m^3/month (1 200 bopm) are subject to lower royalties.

<u>Comparison of Royalty Rates as Function of Price</u>
Old Oil: Alberta royalty rates are considerably lower than comparable rates for Saskatchewan; both regimes are price-sensitive. Royalty rates in Manitoba and B.C. do not respond to price; at a 159 m^3/month well rate (1 000 bopm), the B.C. royalty rate is lower than that of Manitoba.
New Oil: The Saskatchewan heavy oil regime exhibits the lowest royalty rate at prices under \$62/m^3 (\$10/b). Above this price and at a well rate of 159 m^3/month, the Alberta and B.C. regimes produce the lowest royalty rates of all the provinces (Figure 1).

1.1 Conventional Crude Oil (con't)

MANITOBA

Objective:
To take a royalty that is sensitive to production and vintage.

Old Oil
To take 100% of the base royalty.

New Oil
To take 55% of the base royalty.

Low Productivity Wells
No special allowance applies to low productivity wells.

SASKATCHEWAN

Objective:
To take a royalty that is sensitive to well productivity, and crude oil price and vintage.*

Old Oil
To take a royalty of 20% on the first $50/m^3 ($7.95/b) of the price, and 45% on the remainder at a well reference rate of 100 m^3/month (630 bopm).

New Oil
To take a royalty of 15% (non-heavy oil) or 10% (heavy oil) on the first $50/m^3 of the price, and to take 35% (non-heavy oil) or 25% (heavy oil) of the price above $50/m^3 at a well reference rate of 100 m^3/month (630 bopm).

Low Productivity Wells
Wells producing at rates less than approximately 23 m^3/month (145 bopm) are not subject to a royalty. This policy will be reviewed when world oil prices stabilize above $U.S. 20/b.

<u>Comparison of Royalty Rates as a Function of Productivity</u>
Old Oil: At a price of $125.86/m^3 ($20/b), royalty rates for Alberta and B.C. are similar throughout the range of production, and peak at about 39%. Royalty rates for Manitoba and Saskatchewan are also comparable, although no royalty applies in the case of Saskatchewan at a well rate below 23 m^3/month at this price. Rates under the Manitoba and Saskatchewan regimes peak at about 44%.
New Oil: For new oil, the Saskatchewan light crude regime produces the highest royalty rates, while the regime for heavy crude produces the lowest. Royalty rates under the Manitoba regime are similar to those of the Saskatchewan heavy regime at production levels above 23 m^3/month, and the maximum rates under both regimes are less than those of Alberta and B.C. (Figure 2).

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* Effective July, 1988 the calculated royalty rate is reduced by 1% to implement the Saskatchewan Resource Credit (SRC).

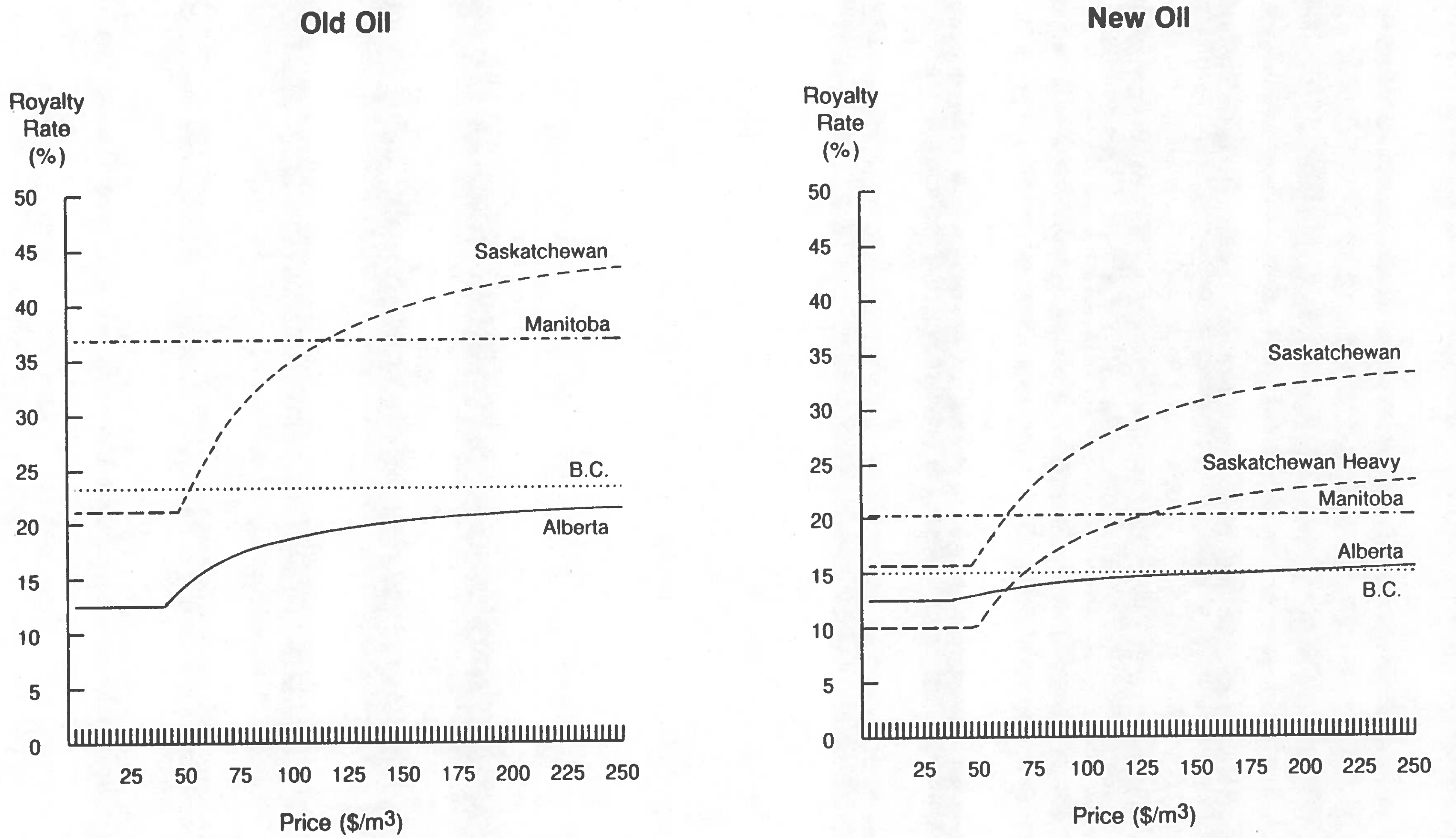
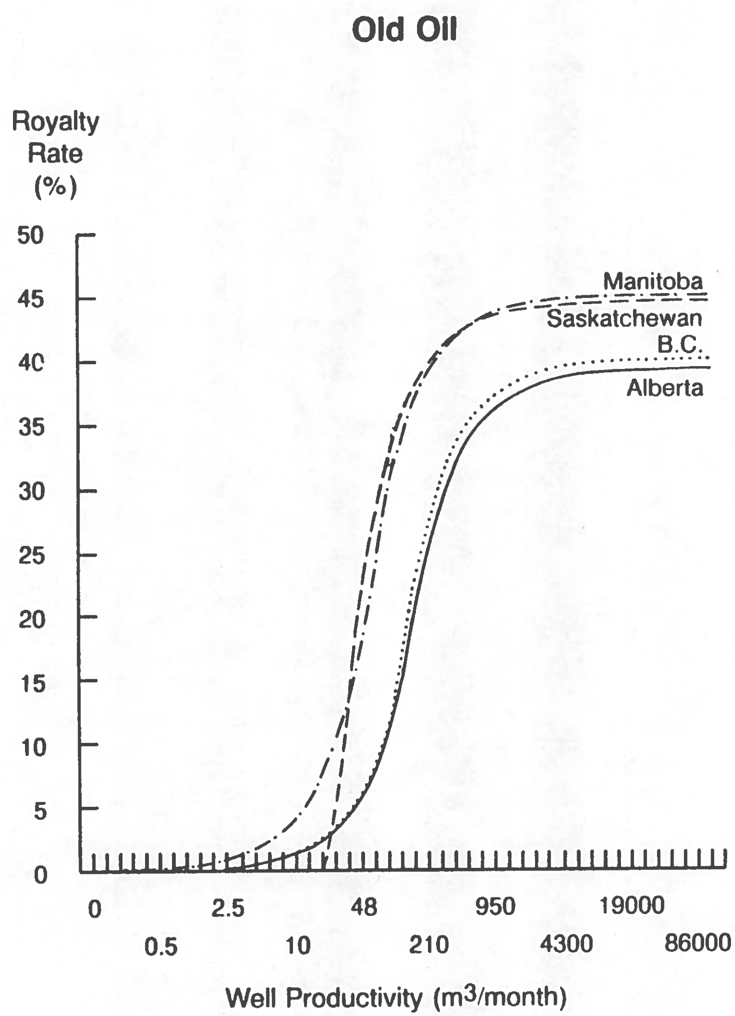


Fig. 1. COMPARISON OF BRITISH COLUMBIA, ALBERTA, SASKATCHEWAN AND MANITOBA CRUDE OIL ROYALTY RATES AS A FUNCTION OF WELLHEAD PRICE
Well Productivity = 159 m^3/mo (1 000 bopm)



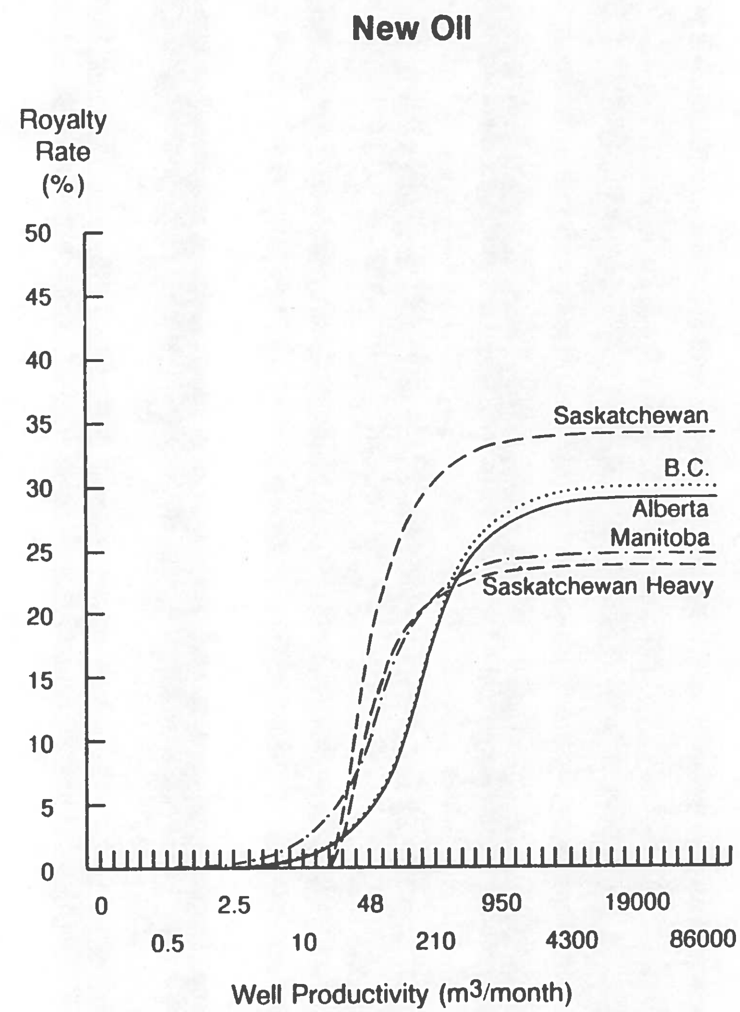


Fig. 2. COMPARISON OF BRITISH COLUMBIA, ALBERTA, SASKATCHEWAN AND MANITOBA CRUDE OIL ROYALTY RATES AS A FUNCTION OF WELLHEAD PRICE
Wellhead Price = $125.86/m^3 ($20/b)

1.2 Natural Gas

B.C.

R% = Royalty rate
P = Selling Price ($\$/10^3m^3$)

Non-Associated Gas

R% = {[750 + 25(P-50)]/P}, with a minimum of 15%
when P < $\$50/10^3m^3$

Conservation Gas

R% = {[400 + 15(P-50)]/P}, with a minimum of 8%
when P < $\$50/10^3m^3$

ALBERTA

R% = Royalty rate
AMP = Average Market Price ($\$/10^3m^3$)

Old Gas (pre-1974)

R% = 22%, when AMP $\leq$ $\$17.75/10^3m^3$ ($0.50/mcf)

R% = {390.50 + [40*(AMP-17.75)]}/AMP
when AMP > $\$17.75/10^3m^3$ ($0.50/mcf)

New Gas (post-1973)

R% = 22%, when AMP $\leq$ $\$17.75/10^3m^3$ ($0.50/mcf)

R% = {390.50 + [27*(AMP-17.75)]}/AMP
when AMP > $\$17.75/10^3m^3$ ($0.50/mcf)
and $\leq$ $\$71.00/10^3m^3$ ($2/mcf)

R% = {1 828.25 + [30*(AMP-71.00)]}/AMP
when AMP > $\$71.00/10^3m^3$ ($2/mcf)

Low Productivity Allowance (Old and New Gas)

R% = Rc – {[(Rc-5)*(16.9-P)^2]/(16.9)^2}
when P < 16.9 10^3m^3/day

where:

Rc = Royalty percent (R%) as calculated before allowance

P = Production (10^3m^3/day)

1.2 Natural Gas (con't)

MANITOBA

R% = Royalty rate
R% = 12.5% of monthly sales

SASKATCHEWAN

R% = Royalty rate

R% = [C*MGP] − SRC
when MGP $\leq$ 115.4 10^3m^3/month (135 mcf/day)

R% = {K-[X/MGP]}-SRC
when MGP > 115.4 10^3m^3/month (135 mcf/day)
to a minimum of 0%

where:

MGP = Production (10^3m^3/month)

C = K/230.76

X = K*57.69

P = Average provincial fieldgate price ($/$10^3m^3$) as determined by the Saskatchewan Department of Energy and Mines

SRC = One percentage point

Old Gas (pre-October 1976)

K = 26 + {32.5*[(P-35)/P]}

New Gas (post-September 1976)

K = 19.5 + {26*[(P-35)/P]}

Gas Associated with Oil

R% = 0%

1.2 Natural Gas (cont'd)

B.C.

Objective:

Effective June 1, 1988 to take a royalty that is sensitive to gas prices above $\$50/10^3m^3$.

Low Productivity Wells

Effective June 1, 1988 there are no special allowances for low productivity wells.

ALBERTA

Objective:

To take a royalty share of production that is sensitive to the prevailing market price (AMP) and the vintage of the reserves, with adjustments for low productivity wells. The royalty volumes are valued at the greater of the selling price, or 80% of the prevailing AMP. The gross unit royalty (R$) is calculated as:

R% = Royalty rate
F = Selling price ($\$/10^3m^3$)
R$ = R%*F, if F $\geq$ 0.8*AMP
R$ = R%*0.8*AMP, if F < 0.8*AMP

Old Gas

To take 22% of the first $\$17.75/10^3m^3$ ($.50/mcf) of the price and to take 40% of the remaining price.

New Gas

To take 22% of the first $\$17.75/10^3m^3$ of the price, 27% of the price between $17.75 and $\$71/10^3m^3$ ($0.50 and $2/mcf), and to take 30% of the remaining price.

Low Productivity Wells

Wells producing at 16.9 10^3m^3/day (600 mcf/day) or less are entitled to an allowance which reduces royalty rates to as low as 5%. This allowance does not apply to solution or associated gas.

<u>Comparison of Natural Gas Royalty Rates as a Function of Price</u>

The Manitoba regime, which is not sensitive to either prices or production, generates the lowest royalty rate of all the provinces at a flat rate of 12.5% of sales. The recently revised B.C. regime produces much lower royalty rates than before at a well rate of 1 295 10^3m^3/month (1 200 mcf/d). Royalty rates produced by the Alberta regime exceed those for B.C. and Manitoba, but are less than those of Saskatchewan over most of the price range (Figure 3).

1.2 Natural Gas (con't)

MANITOBA

Objective:

To take a flat royalty of 12.5% on natural gas consumed or sold from a location.

Low Productivity Wells

There is no special allowance for low productivity wells.

SASKATCHEWAN

Objective:

To take a royalty that is sensitive to well productivity, and natural gas price and vintage.*

Old Gas

To take 20% of the first $35/10^3m^3 ($1/mcf) of the price and 45% of the remaining price at a well reference rate of 250 10^3m^3/month (292 mcf/day).

New Gas

To take 15% of the first $35/10^3m^3 of the price, and 35% of the remaining price at a well reference rate of 250 10^3m^3/month.

Low Productivity Wells

There is no special allowance for low productivity wells.

<u>Comparison of Natural Gas Royalty Rates as a Function of Productivity</u>
Neither the newly revised B.C. regime nor the Manitoba regime is sensitive to production. At a price of $70.99/m^3 ($2/mcf), the Manitoba royalty rate (12.5%) is less than the B.C. rate (18%). Royalty rates generated by the Alberta regime at this price are less than those of Saskatchewan for production levels above 80 10^3m^3/month (about 93 mcf/d) (Figure 4).

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* Effective July, 1988 the calculated royalty rate is reduced by one percentage point to implement the Saskatchewan Resource Credit (SRC).

1.2 Natural Gas (con't)

B.C.

Producer Cost of Service Allowance

All gas producers are eligible to receive the producer cost of service allowance (PCOS) for field gathering, compression and conservation. The rates vary according to H_2S content, field facilities, and geographic location.

Gas Cost Allowance

Producers with natural gas processed at plants not owned by Westcoast Transmission Company Ltd. are entitled to deduct a gas cost allowance (GCA) against royalties. The gas cost allowance is determined in a manner similar to that used in Alberta, with the allowance calculation based on plant flow-through volumes.

ALBERTA

Gas Cost Allowance

The gas cost allowance (GCA) is a deduction from gross royalties payable on natural gas and byproducts to compensate for the costs of gathering, compressing and processing the Crown royalty share. The allowance is determined on the basis of:

1. Operating costs
2. Capital cost allowance, and
3. A 15% return on capital.

The monthly GCA royalty deduction is calculated as the monthly allowable GCA costs reduced by the freehold share of the volumes produced, multiplied by the effective gross royalty rate at the facility for all products. The actual deduction is the lesser of the calculated deduction or 95% of the gross royalty.

MANITOBA

Gas Cost Allowance

No gas cost allowance.

SASKATCHEWAN

Gas Cost Allowance

Saskatchewan producers receive a deemed gas cost allowance of $\$5/10^3m^3$ on old gas and $\$10/10^3m^3$ on new gas. This allowance is in recognition of costs incurred in gathering and compressing the Crown's share of natural gas. The costs of processing gas are excluded from the allowance because the vast majority of natural gas is marketed in a raw (unprocessed) state.

Natural gas royalty rates are calculated on the natural gas price before deduction of the gas cost allowance.

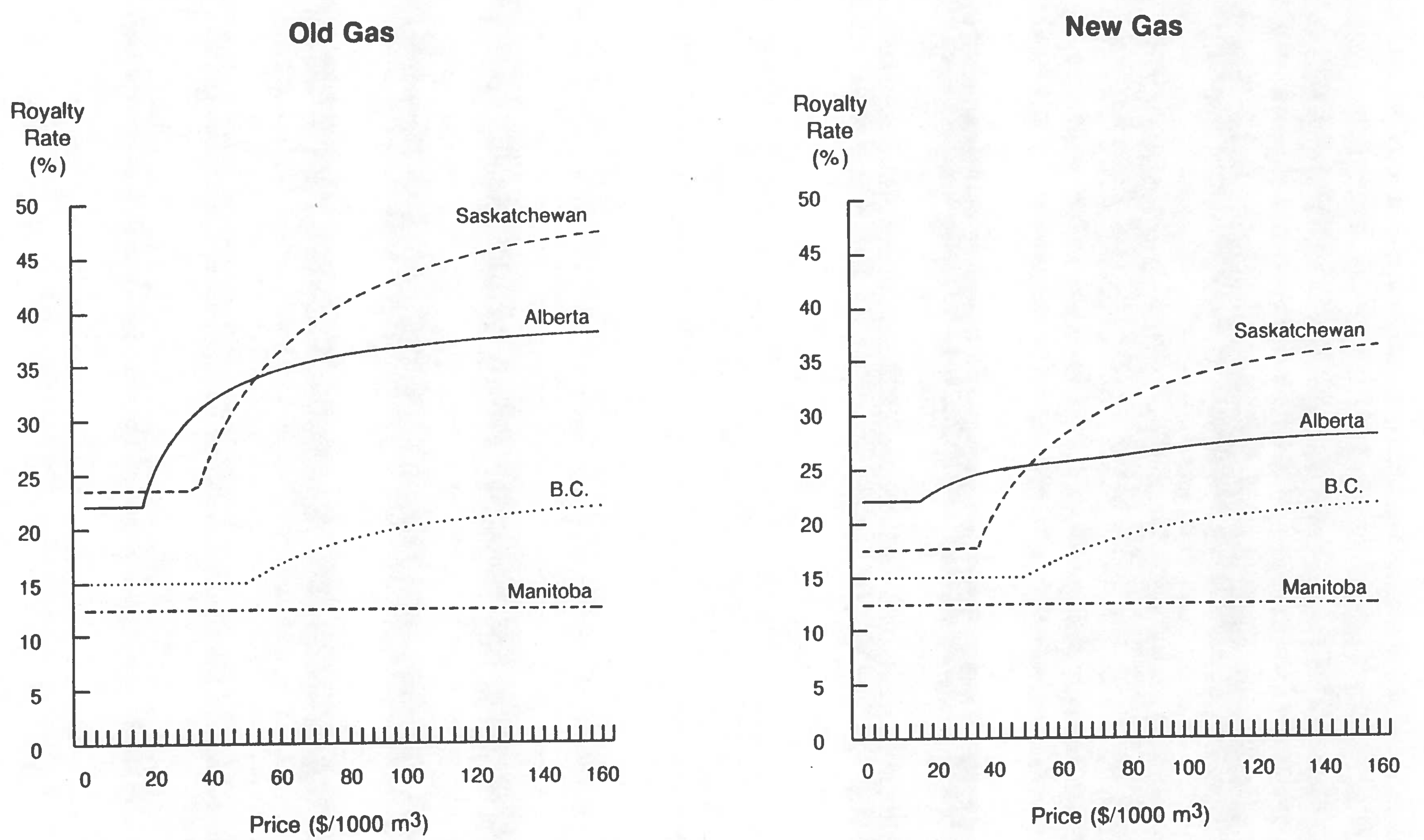

Fig. 3. COMPARISON OF BRITISH COLUMBIA, ALBERTA, SASKATCHEWAN AND MANITOBA NATURAL GAS ROYALTY RATES AS A FUNCTION OF FIELD PRICE

Well Productivity = 1295 $10^3 m^3$/mo (1 200 mcf/d)

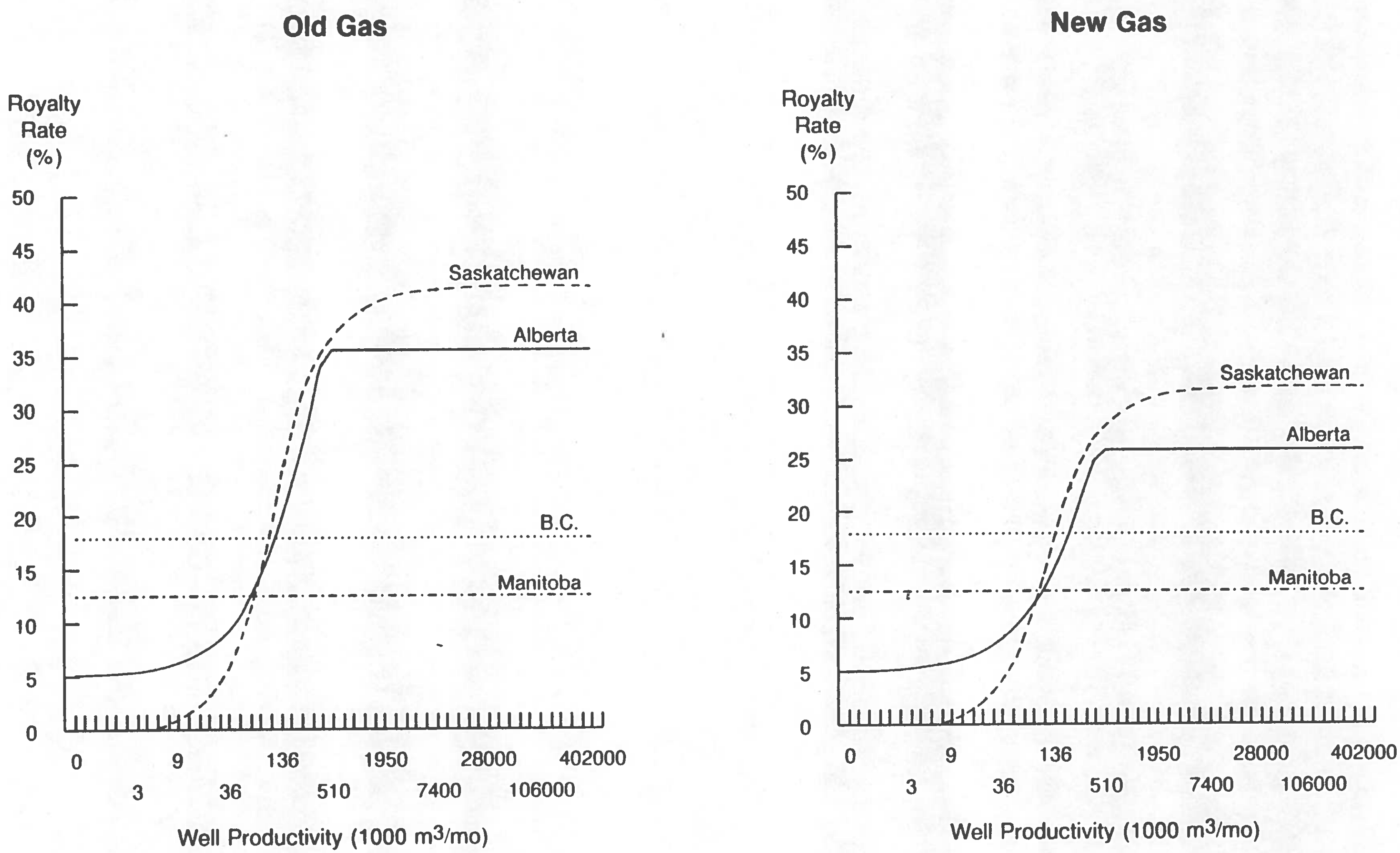

Fig. 4. COMPARISON OF BRITISH COLUMBIA, ALBERTA, SASKATCHEWAN AND MANITOBA NATURAL GAS ROYALTY RATES AS A FUNCTION OF WELL PRODUCTIVITY
Field Price = $70.99/m^3 ($2/mcf)

1.3 Natural Gas Byproducts

B.C.

Royalties on natural gas liquids are levied at a flat rate of 20% of the sales value.

As part of long-term contracts due to expire in 1990-1991, no royalty is paid on sulphur obtained from gas processed by Westcoast Energy for British Columbia Petroleum Corporation (BCPC). Instead, Westcoast Energy sells the sulphur and retains the revenue as compensation for the cost of processing gas for BCPC. BCPC, a Crown corporation, markets virtually all gas produced in the province.

In the few instances where gas is not processed by Westcoast Energy, or where Westcoast Energy processes gas for other marketers, a sulphur royalty of 16 2/3% applies.

ALBERTA

Pentanes Plus:

R% = Royalty rate
R% = {[22*B] + [C*(F-B)]}/F

where:

F = Average selling price ($/m^3)
B = Select Price = $40.90/m^3 ($6.50/b)

Old Pentanes Plus (pre-1974)

C = 50

New Pentanes Plus (post-1973)

C = 35

Objective

To take 22% of the first $40.90/m^3 of the price and 50% and 35% of the price in excess of $40.90/m^3 for old and new pentanes plus, respectively.

Butane & Propane:

Royalty is levied at a rate of 30% of production.

Sulphur

Royalty is levied at a rate of 16 2/3% of production.

1.3 Natural Gas Byproducts (con't)

MANITOBA

Royalties and taxes are not levied separately on natural gas byproducts. The levy on raw natural gas encompasses byproducts.

SASKATCHEWAN

The majority of natural gas byproducts are derived from associated gas, which is not subject to a direct royalty or tax. Byproducts contained in natural gas that is marketed in a raw (unprocessed) state are subject to the natural gas royalty.

1.4 Nonconventional Crude Oil

Oil Sands Royalty

B.C., Saskatchewan and Manitoba have no royalty regimes for oil sands. Alberta has regimes for the two mining projects, Suncor and Syncrude, and the Cold Lake regime for commercial in situ projects. Experimental projects as designated by the ERCB have separate royalty regimes.

Suncor

Alberta receives a percentage of either production or net revenues according to the following schedule:

From July 1, 1987 to December 31, 1991: the greater of 2% of gross production or 15% of net revenues.
After December 31, 1991: the greater of 5% of gross production or 30% of net revenues.

Syncrude

Alberta receives a royalty of 50% of net revenue. Net revenue is calculated as:

Deemed Gross Revenue
– Allowed Operating Costs
– Deemed Interest Expense
– Amortization of Capital Expenditures
– Loss Carry Forwards (if any)
= Net Revenue

The deemed interest expense consists of 75% * 8% of average capital employed. The amortization of capital expenditures commenced in 1984 and encompasses all pre-production and ongoing capital over 20 years on a remaining useful life basis.

Between 1983 and 1988, capital expenditures (termed "special capital costs") qualify for a 100% writeoff in the year incurred, thereby deferring royalties. This royalty adjustment was implemented to encourage Syncrude to expand plant capacity. Royalty benefits occur only if expenditures exceed previously agreed-upon levels. A minimum royalty clause ensures that the minimum joint venture payment would be the lesser of: 5% of gross revenue, or 50% of the net revenue that would have been payable without the implementation of the special capital costs write-off.

Alberta has an option to take a 7.5% gross revenue royalty in place of the 50% net revenue royalty. This option can only be exercised once. Therefore, once the Province opts for a 7.5% gross revenue royalty it cannot revert to a 50% net revenue royalty.

1.4 Nonconventional Crude Oil (cont'd)

Commercial In Situ Production

The fiscal terms applicable to commercial in situ projects are known as the Cold Lake regime because they were first applied to the Esso Cold Lake Project. The royalty consists of a 1% royalty on gross revenue at startup, increasing by 1% every 18 months to 5%. The royalty remains at 5% until payout at which point it converts to 30% of net profit or 5% of gross revenue, whichever is greater.

Net profit is calculated as:

Gross Revenue
– Allowed Operating Costs
– Allowed Capital Costs
= Net Profit

Operating costs and capital costs receive 10% and 1% uplifts respectively to recognize indirect expenses.

Royalty payout is attained when cumulative gross revenue exceeds cumulative operating costs, capital costs and gross royalty. Unrecovered costs are escalated by a 10% return allowance.

Experimental Projects

Bitumen and crude oil produced from experimental projects approved by the ERCB receive a flat royalty rate of 5% of production. Currently, royalty is waived on proprietary natural gas consumed in the production of experimental oil sands and experimental oil.

2. INCENTIVES
2.1 Crude Oil Royalty Holidays

B.C.

Exploratory Oil Royalty Holiday

Effective July 1, 1985 to June 30, 1989 certified exploratory wildcat wells are exempt from Crown royalty for the first 36 producing months. Exploratory wildcat wells must be located at least 7 km from a designated oil or gas pool.

Development Oil Royalty Holiday

Effective July 1, 1985 to June 30, 1989, incremental production from development and infill wells is royalty exempt for the first 24 producing months, or until December 31, 1991 whichever occurs first.

ALBERTA

Crude Oil Royalty Holiday Program (CORHP)

New and deepened oil wells drilled after September 31, 1986 and outside Energy Resources Conservation Board (ERCB) pool boundaries qualify for a royalty holiday of 60 production months. Wells excluded from the program include infill wells and wells with experimental or commercial oil sands status. The length of the holiday was reduced to 36 production months on November 1, 1987.

Effective November 1, 1988 new wells receive the following royalty holidays:

1. Wells spudded between November 1, 1988 and April 30, 1989 receive a royalty holiday of three years.

2. Wells spudded between May 1, 1989 and October 31, 1989 receive a royalty holiday of one year.

In each of the latter two cases the maximum royalty that can be waived is $1 million per well.

2.1 Crude Oil Royalty Holidays (con't)

MANITOBA

Incentive Drilling Program

Wells drilled between January 1, 1987 and January 1, 1992 qualify for royalty/tax free production. The holiday volume is calculated from a formula that is sensitive to price, well location, depth, producing formation and qualifying credits from previous dry holes. The maximum volume is 10 000 m^3 or five years of production, whichever occurs first.

SASKATCHEWAN

Exploratory Oil Royalty/Tax Holiday

Exploratory wells (located at least 3 km from the nearest oil well or producing from geological systems below all other wells within 3 km) qualify for a three-year holiday. Deep exploratory wells meeting this distance requirement, drilled into a geological system older than Mississippian (other than the Bakken formation) and capable of producing oil from depths greater than 1 700 m qualify for a five-year holiday.

Development Oil Royalty/Tax Holiday

Between July 1, 1988 and June 30, 1989 eligible development wells and incremental oil from new or expanded waterflood projects qualify for a two-year royalty holiday. Beyond June 30, 1989 the holiday remains at two years unless crude oil prices stabilize above U.S.$20, when the holiday is shortened to one year. Eligibility is restricted to wells drilled into drainage units where previous drilling has not occurred or where drilling has resulted in dry or abandoned wells. Wells that do not qualify for two-year holidays may be eligible for a one-year holiday. Deep development wells qualify for a three-year holiday.

2.2 Natural Gas Royalty Holidays

B.C.

Natural Gas Royalty Holiday Incentive Program

Effective June 1, 1987 to June 1, 1990 eligible development and exploratory gas wells will be granted royalty exemptions for the first 12 to 36 producing months (see below). Eligibility of wells is based on their location outside existing designated field boundaries (enlarged for the purposes of this program by a one gas-spacing unit ring fence) and on the age of the producing formation.

The length of the holiday is as follows:

i) Within "Area A" (Ft. St. John area) and between May 31, 1987 and June 1, 1989 all eligible wells are entitled to a 12-month holiday. Pre-Mesozoic exploratory wildcat wells receive a holiday of 24 months.

ii) Outside "Area A" and between May 31, 1987 and June 1, 1990 all eligible wells are entitled to a 12-month holiday. Mesozoic or post-Mesozoic wildcat wells receive an 18-month holiday, and pre-Mesozoic wildcats receive a 36-month holiday.

ALBERTA

Deep Gas Royalty Holiday Program (DGRHP)

Effective June 1, 1985, a holiday applies to all new wells or deepened wells drilled into previously undefined gas pools or extensions of existing pools located below 2 500 m. The drilling spacing unit must be wholly outside the deep gas pools as defined by the ERCB.

The holiday is defined in terms of a dollar amount applied against royalties, which increases with well depth and hence the cost of incremental drilling below 2 500 m. The royalty holiday applies until the value of the natural gas and byproducts exempted equals the amount determined by a depth-base schedule. The maximum value is $3.6 million. Entitlements must be used within 10 years of completing drilling.

Note: Saskatchewan and Manitoba do not offer natural gas royalty holidays.

2.3 Enhanced Oil Recovery Relief

B.C.

Incremental oil production from either an approved experimental tertiary recovery project or a commercial tertiary recovery project is subject to a royalty agreement established under Section 93 of the B.C. Petroleum and Natural Gas Act.

Incremental oil from a new well in a waterflood project is entitled to a royalty holiday for the first 24 producing months. All incremental oil production receives "new" oil status for royalty calculation purposes.

ALBERTA

Section 4.2 of the Alberta Petroleum Royalty Regulations allows the operator of an approved tertiary recovery scheme to deduct approved costs from revenues before calculating royalties.

Alberta will provide Section 4.2 royalty relief to a project if two criteria are met. First, the project must receive technical approval from the ERCB under Section 26 of the Oil and Gas Conservation Act. Second, the royalty revenue accruing to the province from tertiary production, net of relief and discounted at 10%, must at least equal the royalty revenue that would have been collected under a suitable waterflood scheme.

2.3 Enhanced Oil Recovery Relief (con't)

MANITOBA

Reduced royalty and tax rates apply to wells in qualifying new or enlarged EOR projects approved after January 1, 1987 and fully implemented before January 1, 1992. These rates are equivalent to 35% of the base Crown royalty rate for old oil, or the corresponding freehold tax incentive rate.

The incentive period is a maximum of 60 months, and is calculated based on the initial production rate and the average initial water cut for wells in the project.

SASKATCHEWAN

EOR projects on Crown lands are subject to a pre-payout royalty of the lesser of 5% of gross revenue or 10% of operating revenue. A minimum royalty of 1% applies before investment payout. The royalty levied after project payout is the greater of 30% of operating revenue or 5% of gross revenue.

EOR projects on freehold lands are not subject to a freehold tax before payout but are levied a post-payout freehold tax of 23% on operating revenue.

Incremental oil production from a new or expanded waterflood project is entitled to a development well holiday.

EOR production is eligible for the Saskatchewan Resource Credit .

2.4 Royalty Tax Credits and Workover Incentives

B.C.

Royalty Tax Credit

No royalty tax credit.

Workover Incentives

No workover incentives.

ALBERTA

Royalty Tax Credit

The Alberta Royalty Tax Credit (ARTC) is a selective Crown royalty reduction aimed at providing small producers with additional cash flow. The credit is calculated as a percentage of net Crown royalties payable to an annual maximum credit for each company or associated group of companies.

Until December 31, 1989, the ARTC is set at 75% of royalties payable to a maximum of $3 million per claimant.

Workover Incentives

No workover incentives.

2.4 Royalty Tax Credits and Workover Incentives (con't)

MANITOBA

Royalty Tax Credit

No royalty tax credits.

Workover Incentives

No workover incentives.

SASKATCHEWAN

Royalty Tax Credit

Crown royalty and freehold production tax rates are eligible for the Saskatchewan Resource Credit reduction of one percentage point, effective June, 1988.

Workover Incentives

Old oil wells (pre-1974) may be reclassified as new oil wells for royalty purposes if the operator undertakes a major workover to improve recoverability.

2.5 Federal Drilling Incentives

Canadian Exploration and Development Program (CEDIP)

CEDIP was implemented by the federal government on April 1, 1987 to offset the effects of the decline in oil prices that occurred through 1986. Between April 1, 1987 and October 1, 1988 the program provided cash incentives of one-third of eligible exploration and development expenses to a maximum of $10 million in expenditures per company each year. Effective October 1, 1988 the incentive rate dropped to 25%. It will drop again on July 1, 1989 to 16 2/3%, and remain at that level until the program is terminated on December 31, 1989.

Canadian Exploration Incentive Program (CEIP)

The federal government implemented CEIP effective October 1, 1988. This program is intended to replace CEDIP, which is being phased out. CEIP entitles companies to a cash incentive equal to 30% of eligible exploration costs to a maximum of $10 million. (Thus, the maximum amount of the grant is $3 million/year for each company.) Eligible costs are Canadian exploratory expenses (CEE) as defined by the Income Tax Act, and these expenses must be funded by the proceeds of flow-through share issues. CEIP will remain in effect at the current rate of 30% until December 31, 1990, when the program will be reviewed.

Tax pools are reduced by the amount of the CEDIP/CEIP grants. Expenses that qualify for earned depletion or that earn offshore tax credits are not eligible.

The cap on expenditures ensures that CEDIP and CEIP will be of greater benefit to small and medium size companies with annual exploration budgets of $10 million or less.

The main difference between CEIP and CEDIP is that CEDIP entitles companies to a cash incentive equal to one-third of eligible exploration and development costs. Under CEIP, the incentive rate is reduced slightly to 30%, and eligibility is limited to exploration expenses that are funded from the proceeds of flow-through shares.

CEDIP will remain in effect until December 31, 1989, but exploration expenses cannot be claimed under both programs. Expenses eligible for both CEDIP and CEIP are subject to a combined annual expense limit (AEL) of $10 million/company.

3. FREEHOLD TAXES
3.1 Crude Oil Freehold Tax

B.C.

Freehold production tax is calculated by levying a mill rate (12.5) on an assessed value of each land tract.

The assessed value is determined on the basis of revenue from petroleum production from that land in the previous year.

ALBERTA

The freehold mineral tax levied on the holder of a petroleum right is the aggregate of crude oil factors (COF) and solution gas factors (SGF) calculated for each well on the basis of production.

COF = R*M*V*T

where:

Q = Production (m^3/year)

R = Prescribed tax rate = 0.269

M = $(0.0833 \cdot Q)^2/105.94$
when Q < 2 288.4 m^3/year (14 400 b/year)

M = (Q/4)-228.84
when Q $\geq$ 2 288.4 m^3/year (14 400 b/year)

V = Price ($/$m^3$)

T = % of total production subject to freehold tax

SGF = R*M*V*T

where:

R = Prescribed tax rate = 0.069

M = Annual solution gas production ($10^3 m^3$/year)

V = Price ($/$10^3 m^3$)

T = % of total production subject to freehold tax

3.1 Crude Oil Freehold Tax (con't)

MANITOBA

Freehold lessees are subject only to that portion of the freehold tax levied on the operator's share of production.

The freehold lessor is responsible for that portion of the tax levied on the royalty share of production. The freehold tax on crude oil is calculated based on the mothly production rate and oil classification (old, new, incentive and holiday oil).

T = Tax rate as % of P
P = Production (m^3/month)

Old Oil

$T = 0$, when $P \leq 20$
$= [(0.43P)-8.24]$, when $20 < P < 65$
$= [42.76-(1\,500/P)]$, when $P \geq 65$

New Oil

$T = 0$, when $P \leq 36$
$= [(0.23P)-8.11]$, when $36 < P < 65$
$= [19.59-(820/P)]$, when $P \geq 65$

Incentive Oil

$T = 0$, when $P \leq 56$
$= [9.27-(510/P)]$, when $P > 56$

Holiday Oil
$T = 0$, for all volumes

SASKATCHEWAN

The freehold tax on oil is derived by calculating the royalty rate according to the Crown royalty formula and subtracting a production tax factor (PTF).

PTF = 6.9 for old oil
= 10.0 for new oil

The intent is to equalize netbacks from Crown and freehold production.

New freehold wells are entitled to a tax holiday, the duration of which is determined in the same manner as for crude oil royalty holidays.

3.2 Natural Gas Freehold Tax

B.C.

Freehold production tax is calculated by levying a mill rate (12.5) on an assessed value of each land tract.

The assessed value is determined on the basis of revenue from petroleum production from that land in the previous year.

ALBERTA

The field gas factor (FGF) is calculated for each well on the basis of raw (unprocessed) natural gas production. The field gas factors for the wells associated with each petroleum and/or natural gas right are aggregated and levied on the owner of the rights as the freehold mineral tax.

FGF = Field gas factor

ADP = Average daily production

FGF = R*M*V*T
when ADP $\geq$ 16.9 $10^3 m^3$/day (600 mcf/day)

FGF = M*V*A*T
when ADP < 16.9 $10^3 m^3$/day (600 mcf/day)

where:

R = Prescribed tax rate = 0.069

V = Value ($\$/10^3 m^3$)

M = Annual production ($10^3 m^3$/year)

T = Taxable quantity as % of field gas recovered

A = $R - \{[(R-0.01)*(16.9-ADP)^2]/(16.9)^2\}$

3.2 Natural Gas Freehold Tax (con't)

MANITOBA

Freehold lessees are subject only to that portion of the freehold tax levied on the operator's share of production. The freehold lessor is responsible for that portion of the tax levied on the royalty share of production.

The freehold tax is calculated as 1.2% of the volume produced.

SASKATCHEWAN

The freehold tax on natural gas is derived as for crude oil, by calculating the royalty rate according to the Crown royalty formula and subtracting a production tax factor (PTF).

PTF = 6.9 for old gas
= 10.0 for new gas

The intent is to equalize netbacks from Crown and freehold production.

4. CORPORATE TAXES

4.1 Federal Taxes

Effective July 1, 1988, the net federal corporate income tax rate (after the 10% abatement for income taxes levied by the provinces) is 28%. A federal surtax levied at 3% of tax owed is applicable to corporations for an indefinite period. Corporations are allowed the following deductions from income: operating costs, capital cost allowances, interest expenses, exploration and development expenses, resource allowance and in some cases earned depletion. Investment tax credits also reduce federal tax liability. No deduction can be claimed for provincial royalties paid.

Capital cost allowance provides a deduction against income for depreciating property. Many classes of depreciable property exist, the more relevant being Class 10 for oil and gas equipment. Class 10 allows a 30% write-down of equipment on a declining balance basis.

Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expense (CEE); Canadian Development Expense (CDE); and Canadian Oil and Gas Property Expense (COGPE). The CEE balance of exploration expenditures can be fully deducted against income with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 10% of the COGPE balance can be applied against income. As mentioned on page 26, the federal government offers cash incentives under CEIP and CEDIP, which must be deducted from eligible tax pools.

The resource allowance is a deduction equal to 25% of taxable net revenue ("resource profits"), and is computed as gross revenue (including production royalties receivable and deemed income in B.C.) less the sum of: operating costs, production royalties payable, general production expenses, CDE and CEE, deductible Crown lease rentals, and capital cost allowances. The resource allowance does not reduce the tax saving advantages related to the exploration and development expenditures discussed above. Resource allowance not claimed in the current year cannot be carried forward.

The earned depletion allowance, an additional income tax deduction, has largely been phased out with respect to conventional oil and gas production. It still applies to oil sands mining, tertiary production and in situ bitumen production. From July 1, 1988 until its expiry on December 31, 1989, the earned depletion allowance is equal to 16 2/3% of exploration and development expenditures.

Federal tax liability can also be reduced by investment tax credits (ITC). The amount of the credit is equal to a percentage of the cost of the qualifying asset. The general ITC rate is currently 3%, but will eliminated in 1989. To the end of 1988, unused ITC credits are refundable in cash to some extent. Unused ITC can be carried back three years or forward ten years. An exploration tax credit of 25% of qualifying well costs in excess of $5 million remains in effect until December 31, 1990. Qualifying costs do not include Canadian exploration and development overhead expenses, financing charges, or expenses subject to PIP. Because of the $5 million cost qualification, the exploration tax credit applies mainly to wells drilled in frontier areas. Wells with lower exploration costs may qualify for CEIP or CEDIP.

4.2 Provincial Taxes

B.C.

Basic Corporate Tax

Effective January 1, 1988 the rate is 14% of taxable net income.

Royalty Deductibility

The B.C. provincial royalty tax deduction is equal to 14% of: the royalty less the resource allowance.

The rebate can either increase or decrease the tax on a corporate basis.

ALBERTA

Basic Corporate Tax

15% of taxable net income.

Royalty Deductibility

The Alberta provincial royalty tax deduction is equal to 15% of: the disallowed Crown royalty less the 25% resource allowance. The royalty tax deduction can only reduce the tax. The reduction cannot increase the tax. Unused deductions can be carried forward.

4.2 Provincial Taxes (con't)

MANITOBA

Basic Corporate Tax

The basic corporate tax rate is 17% for corporations whose annual income exceeds $200,000, and 10% where income is less than this amount. In calculating income tax, gross freehold royalty payments and the resource allowance are deductible.

Corporate Tax Holiday

Businesses incorporated after August 8, 1988 and before January 1, 1991 will be eligible for a corporate income tax holiday in their first year of operation, and phased increases over the next four years.

SASKATCHEWAN

Basic Corporate Tax

17% of taxable net income until January 1, 1989, when the rate is reduced to 15%.

Corporate Capital Tax Surcharge

Effective July 1, 1988 large resource corporations will be assessed a corporation capital tax surcharge, which is equal to the difference between the existing corporation capital tax liability and 2% of a corporation's value of Saskatchewan resource sales.

Royalty Deductibility

The Saskatchewan provincial royalty tax deduction is the lesser of the Saskatchewan provincial tax payable, or 17% of: royalties/freehold production taxes less the resource allowance. The deduction cannot increase tax. Unused deductions can be carried forward.