OIL AND GAS FISCAL REGIMES

Western Canadian Provinces and Territories

Alberta
ENERGY

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For additional copies of this report contact:

Gas Development Business Unit
Electricity & Gas Division
Alberta Department of Energy
9945 - 108th Street
Edmonton, Alberta, Canada T5K 2G6
Phone: (780) 427-6504
Fax: (780) 422-9677
E-mail: lori.prusko@gov.ab.ca

For additional information please refer to the list of contacts at the end of this report.

This report summarizes the petroleum fiscal regimes for the Western Canadian provinces and territories. The regimes applicable to Canadian Federal lands are also described.

Descriptions are provided for each resource commodity: oil sands, crude oil, and natural gas and natural gas by-products (including gas from coal - coal bed methane - CBM). Differences in the regimes reflect the unique circumstances in each jurisdiction, particularly the characteristics of the resource base.

In Alberta and Saskatchewan, the province owns approximately 80% of petroleum and natural gas resource rights; the remaining rights are classified as "freehold rights". In British Columbia, the Crown owns almost 100% of producing oil and gas rights.

The total revenue received by a province from the allocation of resource development rights generally has two major components: revenue from the allocation of the right to produce the oil or gas (bonus bids), and revenue from royalties on production.

The revenue from bonus bids comes from the allocation of rights by public tender. Industry submits sealed bids for each parcel. The highest bidder is typically awarded the parcel. The amount paid reflects industry's estimate of the difference between the present value of production revenues and the present value of costs, taxes, and royalties over the time there is production from the leased lands. This tends to make total Crown revenues from comparable leases similar, despite differences in royalty rates and royalty reduction features.

Each of these provinces has systems in place for the disposition and posting of available Crown rights and identification of access constraints and potential land use conflicts. In Alberta, information letters are issued for the upcoming calendar year to advise industry of deadlines for submission of their posting requests, publication of postings and the actual sales dates which usually occur twice per month. The other two provinces follow a similar process, but their sales dates are less frequent.

NOTE: The information provided here does not deal further with bonus bids or land tenure issues. Also, the information is for comparative and ease of reference purposes only. Current legislation and reporting guidelines for specific features of each of these regimes should be obtained from the contacts listed at the end of this report.

Figure 1 identifies the various fiscal components that are typically grouped to form alternative fiscal regimes employed around the World, illustrating the key components of Alberta's fiscal regimes. The oil sands are classified as unconventional resources with the regime alternatively referred to as a Resource Rent Tax or Revenue (R) minus Costs (C) royalty. The regimes for conventional oil and gas resources in Alberta are classified as a sliding scale royalty, with the scales based on time, energy content, price, and well productivity, in the case of gas; and on time, price, well productivity, and density in the case of oil.

Figure 2 provides a conceptual illustration of the distribution of resource revenue from a given pool or project. The figure shows typical cost categories such as investment and operating costs, provincial and federal taxes, return on investment, royalties, and bonus payments.

Classifications

The Western provinces generally classify their conventional oil and gas resources into tiers according to date and, in the case of oil, density. Date can refer to the date of discovery, the finished drilling date of the well, and/or the date the oil and gas rights were acquired. The royalty formulas are set so that the newer classifications and the higher densities (heavy oil) pay less royalty.

Date Classifications

BRITISH COLUMBIA

Conservation Gas (gas produced from oil wells) is not date sensitive

NON-CONSERVATION GAS

Base 15 Gas	wells drilled prior to June 1998
Base 12 Gas	wells drilled after June 1, 1998 except those that are Base 9 Gas.
Base 9 Gas	wells drilled on lands acquired after May 1998 and before January 2004 and which are completed within 5 years of the date rights are issued.

NON HEAVY OIL

Old Oil	pre-November 1975
New Oil	post-October 1975
Third Tier Oil	post-June 1, 1998 oil or Post-December 1999 incremental oil from Enhanced Oil Recovery (EOR) schemes.
Heavy Oil	not date sensitive.

ALBERTA

Old Gas	pre-1974 (rates modified in 1992)
New Gas	post-1973 (rates modified in 1992)
Old Oil	pre-April 1974
New Oil	post-March 1974
Third Tier Oil	post-September 1992

SASKATCHEWAN

Old Gas	pre-October 1976
New Gas	post-September 1976
Third Tier Gas	post-February 8, 1998
Fourth Tier Gas	post-September 2002
Old Oil	pre-1974 (does not apply to heavy or southwest designated oil)
New Oil	post-1973
Third Tier Oil	post-1993 (does not usually apply to horizontal wells)
Fourth Tier Oil	post-September 2002 vertical wells and post September 1992 horizontal wells after production of incentive volumes.

MANITOBA

Gas	Manitoba does not classify its natural gas resources by date.
Old Oil	prior to April 1, 1974
New Oil	on or after April 1, 1974 and prior to April 1, 1999 (oil produced from drilled and re-entered vertical wells, oil produced from horizontal wells, and oil produced from old oil wells approved in an Enhanced Oil Recovery scheme)
Third Tier Oil	on or after April 1, 1999 (oil produced from drilled, re-entered and reactivated vertical wells; oil produced from the major workover of a marginal wells after April 1, 2001; and, oil produced from old or new oil wells approved in an Enhanced Oil Recovery scheme after April 1, 1999).
Holiday Oil	January 1, 1987 to January 1, 2004 (volume of oil determined under The Manitoba Drilling Incentive Program).

Density Classifications

BRITISH COLUMBIA

Heavy Oil	oil with density > 890 kg/m^3
Non-heavy Oil	oil with density < 890 kg/m^3

ALBERTA

Heavy Oil	oil with density > 900 kg/m^3
Non-heavy Oil	oil with density < 900 kg/m^3

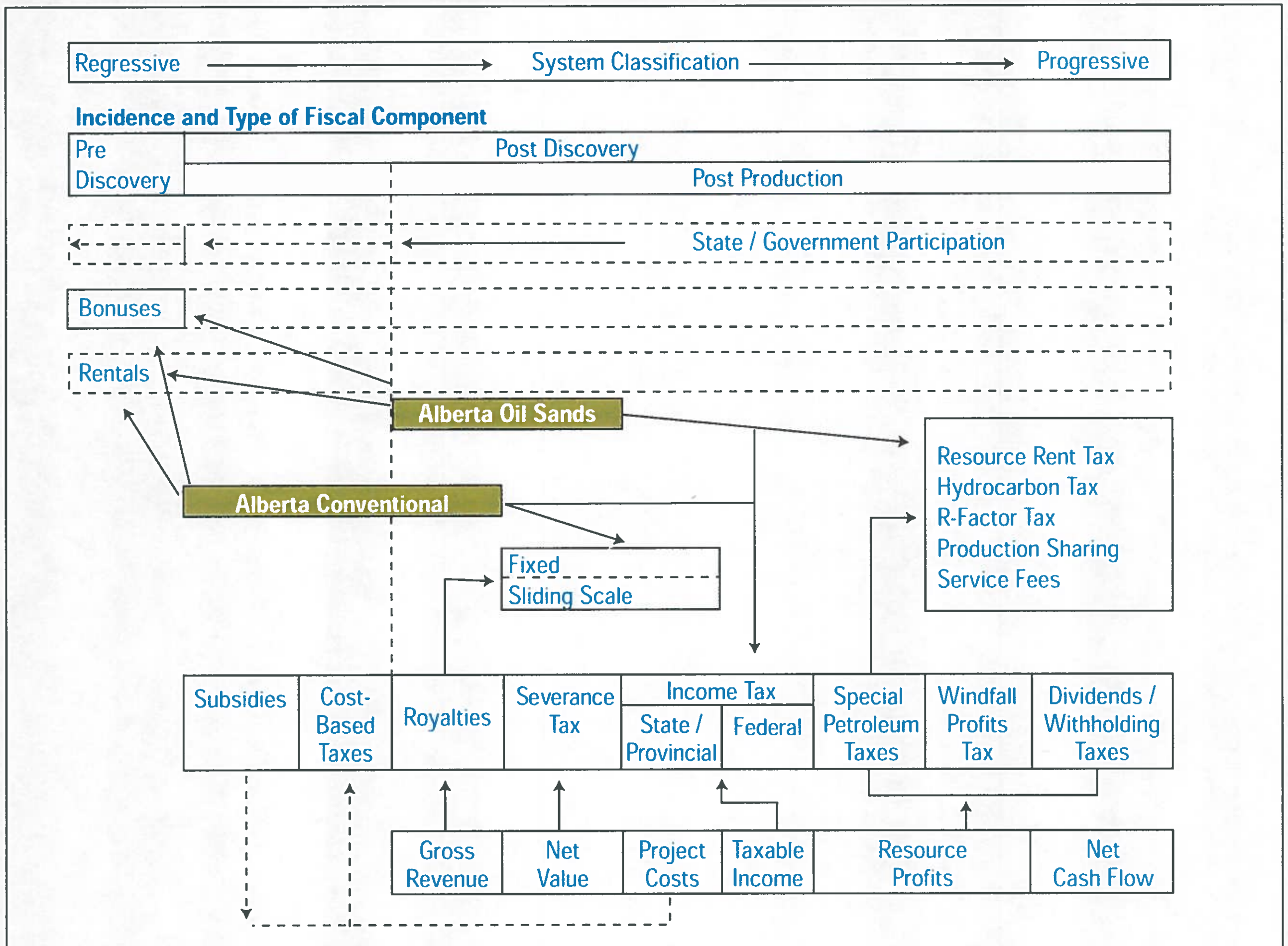
SASKATCHEWAN

Saskatchewan's oil classifications are area-based. Heavy oil includes all oil produced in the Lloydminster and Kindersley-Kerrobert areas (townships north of Township 21 in Ranges 5 through 29, West of the Third Meridian), other than oil produced from the Viking zone. Southwest-designated oil is oil produced from wells drilled after February 8, 1998 and incremental oil produced from waterfloods commencing operation after February 8, 1998 in the southwest area of the province. Although there are no specific density classifications within each area, the density of Heavy oil and Southwest designated oil is typically comparable to Alberta's heavy oil. All other oil is classified as non-heavy.

MANITOBA

Manitoba does not classify its oil resources by density.

WORLD FISCAL SYSTEMS
ALTERNATIVE COMPONENTS AND CLASSIFICATIONS



SOURCE: Alberta Department of Energy; after Daniel Johnston - "International Petroleum Fiscal Systems and Production Sharing Contracts", 1994

FIGURE 2: STYLIZED ILLUSTRATION OF PROJECT RESOURCE REVENUE SHARES

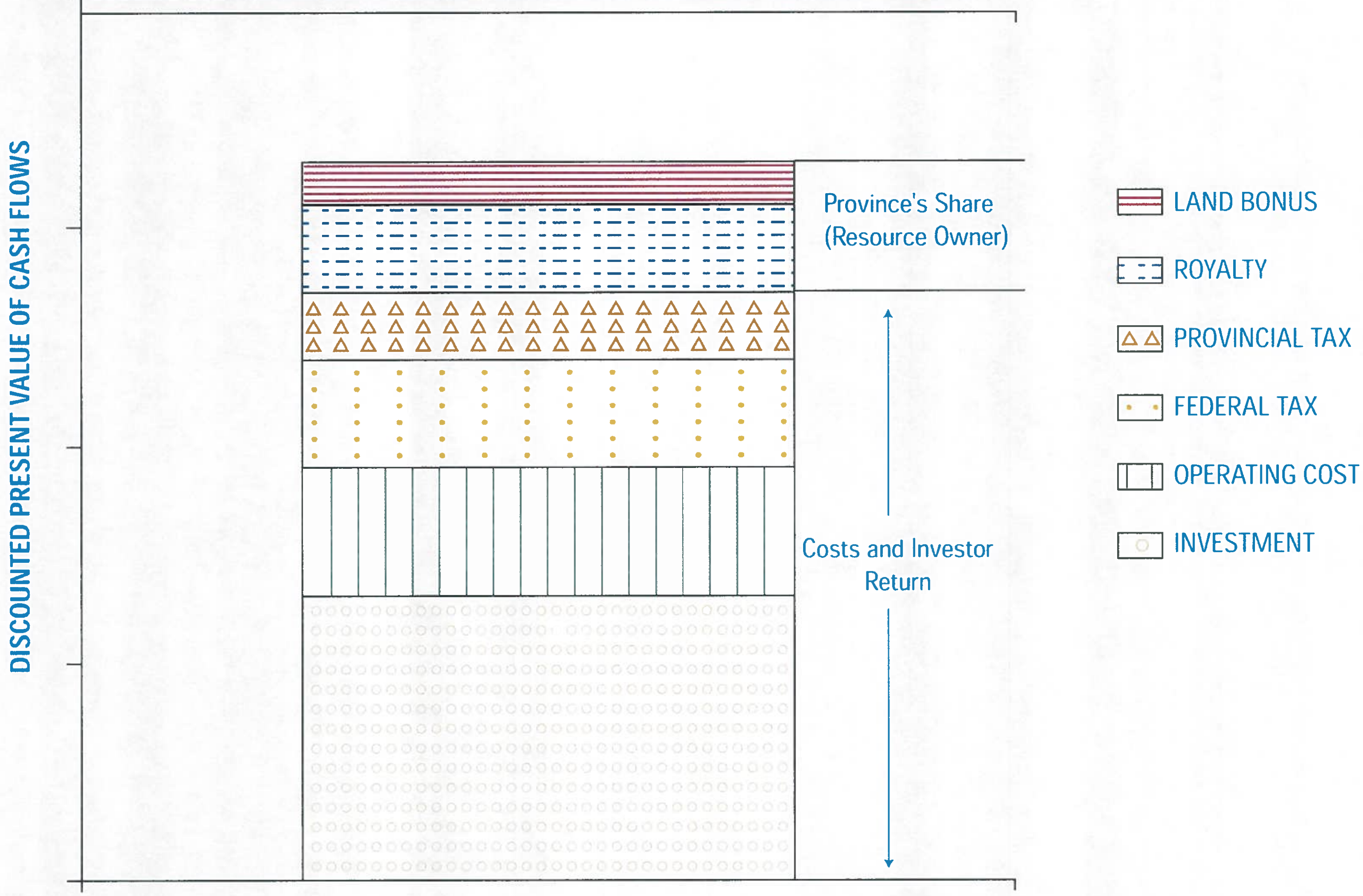


Figure 2: General illustration of the allocation of project revenues. The category for costs and investor return includes a component for risk. This reflects the portion of the project economic rent that is left with the investor to avoid taking quasi rent and to fund ongoing exploration.

1. ROYALTIES

A. Natural Gas

i. GAS ROYALTY FORMULAS AND RATES

Distinction is made between conservation gas (solution gas produced in association with oil) and non-conservation gas.

Conservation Gas

The conservation gas royalty formula retains 8% of the price, when the price is less than or equal to $\$50/10^3m^3$, and 15% of the price in excess of \$50.

R% = [400 + 15 (RP - 50)] / RP (to a minimum of 8%)

Non-Conservation Gas

BASE 15 GAS
For wells drilled before June 1, 1998, the royalty formula retains 15% of the price, when the prices are less than or equal to \$50, and 25% of the price in excess of \$50.

R% = [750 + 25 x (RP - 50)] / RP (to a minimum of 15%)

BASE 12 GAS
For wells drilled after June 1998 except those that are Base 9 Gas, the royalty formula retains 12% of the price, when the prices are less than or equal to the Select Price, and 40% of the price in excess of the select price subject to a maximum royalty rate of 27%.

R% = [12 x SP + 40 (RP - SP)] / RP (not less than 12% and not more than 27%)

BASE 9 GAS
For wells on lands acquired between June 1, 1998 and December 31, 2001 and which are completed within 5 years of the date rights are issued, the royalty formula retains 9% of the price, when the prices are less than or equal to the Select Price, and 40% of the price in excess of the select price subject to a maximum royalty rate of 27%.

R% = [9 x SP + 40 (RP - SP)] / RP (not less than 9% and not greater than 27%)

WHERE:

R% = Royalty rate

RP = Reference Price ($\$/10^3m^3$) is the greater of Selling Price at the plant inlet or PMP (Posted Minimum Price).

SP = Select Price ($\$/10^3m^3$) used in calculating royalty.

For 2003 and all prior years, the select price is $\$50/10^3m^3$. For Non-Conservation gas produced from wells drilled prior to June 1998, the select price is permanently fixed at $\$50/10^3m^3$.

Low Productivity Wells

A low productivity rate reduction applies for conventional natural gas wells producing less than 5 10^3m^3 per day in a producing month.

R% = Rc% x [(5000 - ADV) /5000]²

WHERE:

Rc = Royalty percent (R%) as calculated before the low productivity reduction.

ADV = the average daily raw gas production from the well event during the month in cubic metres.

Natural Gas Liquids Royalty

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

Sulphur

Royalties on sulphur are levied at a flat rate of 16 2/3 % of the sales volume.

ii. COST ALLOWANCES

Producer Cost of Service Allowance

Gas producers are eligible to receive the producer cost of service allowance (PCOS) for field gathering, dehydration, compression, field processing and conservation. The PCOS allowance is a plant specific, fixed rate deduction from gross natural gas royalty.

Royalty clients that utilize a producer-owned gas plant or sales line are eligible for annual capital and operating cost allowances. The capital cost allowance calculation includes a 15% return on investment, increased from 12.5%, effective June 1998.

For detailed information on PCOS rates, refer to the contacts listed at the end of this report.

iii. GAS PROGRAMS

Natural Gas Royalty Reduction

Non-Conservation Gas from wells drilled on land rights acquired between June 1, 1998 and December 31, 2003 and which are completed within 5 years of the date rights are issued, qualify for a reduced royalty rate on their lifetime production volumes. Under this program, the minimum royalty rate has been reduced to 9%.

Deep Royalty Program

Refer to Ministry of Energy and Mines 2003 news release 2003EM0008-000536

A well-depth deduction amount may be deducted from a reporting entity's royalty payable if the reporting entity consists of nothing more than an interest in a single well and:

(a) the well has a well depth of at least 2,500 metres;

(b) the well has a spud date after June 30, 2003 and before July 1, 2008.

The credit 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 metres.

The royalty credits are tied to individual wells and applied against their future royalties. They are not transferable between wells.

Table 1: Deep Royalty Holiday Credits

WEST SPECIAL SOUR			[illegible] SPECIAL SOUR		
Depth	Cumulative Value	Incremental Value	Depth	Cumulative Value	Incremental Value
Metres (m)	$000	$/Metre	Metres (m)	$000	$/Metre
2,500	0	4,200	2,500	0	1,500
3,000	2,100	600	3,000	750	650
3,500	2,400	700	3,500	1,075	750
4,000	2,750	800	4,000	1,450	850
4,500	3,150	900	4,500	1,875	1,000
5,000	3,600	1,000	5,000	2,375	1,100
5,500	4,100	-	5,500	2,925	-

WEST SWEET			EAST SWEET		
Depth	Cumulative Value	Incremental Value	Depth	Cumulative Value	Incremental Value
Metres (m)	$000	$/Metre	Metres (m)	$000	$/Metre
2,500	0	3,800	2,500	0	1,400
3,000	1,900	550	3,000	700	600
3,500	2,175	600	3,500	1,000	700
4,000	2,475	700	4,000	1,350	800
4,500	2,825	800	4,500	1,750	900
5,000	3,225	900	5,000	2,200	1,000
5,500	3,675	-	5,500	2,700	-

Marginal Royalty Program

Refer to Ministry of Energy and Mines 2003 news release 2003EM0008-000536.

The current British Columbia low rate royalty relief plan allows all wells in the province to qualify if their production falls below 5000 m^3 per day. A new method was developed that would provide more royalty relief to a targeted percentage of the wells based on well depth and initial production rates.

A well event is a marginal well event in any producing month if:

(a) the well event produces only non-conservation gas.

(b) the average daily natural gas production volume for the well event, over the first 12 calendar months following the calendar month in which marketable gas is first produced from the well event or is first produced from the reactivated well event since its reactivation, is, when divided by the well depth of the well event over that period, less than 23 m^3 for every metre of well depth.

(c) in the producing month, the average daily natural gas production volume for the well event is less than 25,000 m^3.

(d) the 12 calendar month period referred to in paragraph (c) ends after June 30, 2004 and before July 1, 2009.

ROYALTY CALCULATION:

Marginal Well Royalty Rate

The royalty rate for marginal wells is determined by the Base 9 formula with the SP set at $\$70/10^3m^3$

Marginal Well Low Productivity Adjustment

Each marginal well also gets a low productivity reduction factor against the royalty percentage in accordance with the following formula:

$P \times [(25{,}000 - S) / 25{,}000]^2$

WHERE:

P is equal to the volume of natural gas produced in the producing month from the marginal well divided by the sum of the volumes of natural gas produced in the producing month from all of the reporting entity's wells that are marginal wells, and

S is equal to the average daily natural gas production volume for the marginal well in the producing month.

Summer Royalty Program

Refer to Ministry of Energy and Mines 2003 news release 2003EM0008-000536

The Summer Drilling Incentive will provide a 10% royalty credit of goods and services costs attributable to individual wells. The credit will be added to a royalty bank to a maximum of $100,000 per well for wells spudded after June 30, 2003 and before December 1, 2003, after March 31, 2004 and before December 1, 2004 or after March 31, 2005 and before December 1, 2005.

B. Oil

Distinction is made between old oil, new oil, third-tier oil, and heavy oil.

Old Oil

The old oil royalty formula retains between 0 and 12% of production for well production rates between 0 and 95 m^3/month. At production rates greater than 95 m^3/month, the marginal rate applied to production is 40%.

New Oil

The new oil royalty formula retains between 0 and 15% of production for well production rates between 0 and 159 m^3/month. At rates greater than 159 m^3/month, the marginal rate applied to production is 30%.

Third Tier Oil

The production sensitive royalty formula retains between 0 and 12% of production for well production rates between 0 and 159 m^3/month. At well rates greater than 159 m^3/month, the marginal rate applied to production is between 12% and 24%. The royalty rate is also determined by multiplying the production sensitive royalty formula by a price factor. A 50% rate reduction applies for Wellhead prices below $\$125/m^3$. A rate reduction between 50% and 0% applies for Wellhead prices between $\$125/m^3$ and $\$175/m^3$.

Heavy Oil

The heavy oil royalty rate is set by multiplying the production sensitive royalty rate by a price factor. Heavy oil wells producing at rates less than 20 m^3 per month are not subject to a royalty. At a $\$150/m^3$ Wellhead price, the heavy oil royalty formula retains between 0% and 11% of production for well production rates between 20 m^3/month and 200 m^3/month, and 18% of production above 200 m^3/month.

Low Productivity Wells

Lower royalty rates apply to old oil wells producing at rates less than 95 m^3/month, new or third tier oil wells producing at rates less than 159 m^3/month, and heavy oil wells producing under 200 m^3/month. There is no minimum rate for oil.

i. OIL ROYALTY FORMULAS AND RATES

$R\% =$ *Royalty rate*

$Q =$ *Production (m^3/month)*

Old Oil And New Oil:

$R\% = (Q / K) \times 100$ when $Q \leq C$

$R\% = [A + (B \times (Q - C)) / Q] \times 100$ when $Q > C$

Old Oil (Pre-november, 1975)

$K = 792$

$A = 11.4$

$B =$ *Percent of incremental production* $= 40\%$

$C =$ *Production threshold* $= 95\ m^3/month$

New Oil (Post-October, 1975)

K = 1058

A = 23.9

B = Percent of incremental production = 30%

C = Production threshold = 159 m^3/month

Third Tier Oil (Post December 1999)

R% = (P x Q) / K x 100 when Q ≤ C

R% = [P x A + P x (B x (Q - C))] / Q x 100 when Q > C

K = 2645

A = 9.56

B = Percent of incremental production = 12%

C = Production threshold = 159 m^3/month

P = Price Factor which is the lesser of:

(a) $1 + \dfrac{3.5 \times (\text{Wellhead Price - Third Tier Oil Threshold Price})}{\text{Wellhead Price}}$

(b) 2

The Third Tier Oil Threshold Price has been set at $125/$m^3$ since January 1, 2000.

The Wellhead Price is the greater of:

(a) the average net value of that oil at the Wellhead determined in accordance with Section 7(3)(b) of the Regulation (see Section 6.5, field C6 on the Monthly Crown Royalty Statement - Oil, page 6.5-7), and

(b) the Threshold Price

Heavy Oil (not date sensitive)

R% = 0 when Q ≤ 20

R% = (P x (Q - 20)²) / (A x Q) x 100 when Q > 20 ≤ 200

R% = P x ((Q - 200) x B + K) / Q x 100 when Q > 200

K = 13.5

A = 24

B = Percent of incremental production = 11%

C1 = Minimum production threshold = 20 m^3/month

C2 = Maximum production threshold = 200 m^3/month

P = Price Factor which is equal to:

(a) $1 + \dfrac{2.5 \times (\text{Wellhead Price - Heavy Oil Threshold Price})}{\text{Wellhead Price}}$

The Heavy Oil Threshold Price has been set at $110/$m^3$ since January 1, 2000.

The Wellhead Price is the greater of:

(a) the average net value of that oil at the Wellhead determined in accordance with Section 7(3)(b) of the Regulation (see Section 6.5, field C6 on the Monthly Crown Royalty Statement - Oil, page 6.5-7), and

(b) the Threshold Price.

ii. OIL PROGRAMS

1. Drilling Programs

DISCOVERY OIL ROYALTY HOLIDAY

Oil produced from a new pool discovery well is royalty exempt for the first 36 producing months.

2. Enhanced Oil Recovery (EOR) Royalty Relief

Incremental oil that is derived from any pressure maintenance scheme, or an enhanced oil recovery scheme that was approved after December 31, 1999 is classified as Third Tier Oil.

C. Gas from Coal

Background

In March 2002, British Columbia announced changes to the royalty/tax regulation to address the unique resource development issues surrounding coalbed methane.

Objective

The objective of the coalbed methane royalty regime is to recognize the unique development and economic issues surrounding this new resource. Principally, water handling costs, low well productivity and deferred revenues. While the overall conventional royalty structure remains intact, the coalbed methane royalty regime features the following changes:

Water Handling Producer Cost of Service Allowance- Effective March 1, 2002, a water handling PCOS category has been created for approved coalbed methane projects. Scheduled water handling related capital and operating costs are captured in this new category. Certain capital costs incurred during experimental phases may be carried forward. Actual costs will be used for each project.

Royalty/Tax Bank- Each producer with an interest in a coalbed methane project will be provided with a project royalty/tax bank to collect excess PCOS allowances. Banks are transferable with project interest. Banks may not be used to offset royalties/taxes assessed on conventional oil and gas production, or between coalbed methane projects.

Low Productivity Threshold for coalbed methane wells has been increased from 5 10^3m^3 for conventional gas wells, to 17 10^3m^3 for coalbed methane wells.

Royalty Credit- A $50,000 royalty credit and $30,000 production tax credit for wells drilled and completed on Crown and Freehold land, respectively, by February 24, 2004. The royalty/tax credit will be applied to royalty/tax banks upon approval from the Oil and Gas Commission. Royalty/tax credits will be apportioned according to interest in a project.

2. FREEHOLD TAXES

The Freehold Production Tax is calculated and payable on a monthly basis in a manner very similar to the royalty calculation.

A. Natural Gas Freehold Mineral Tax

The tax rate for gas is expressed as a percent is as follows:

CONSERVATION GAS

Rate = 5%, when $P \leq \$50/10^3m^3$/month

Rate = [(245 + 9 x (P - 50)) / P], when $P > \$50/10^3m^3$/month

NON-CONSERVATION GAS

Rate = 9%, when $P \leq \$50/10^3m^3$/month

Rate = [(460 + 15 x (P - 50)) / P], when $P > \$50/10^3m^3$/month

WHERE:

P is the Reference Price defined as the greater of the selling price at plant inlet or the Posted Minimum Price (PMP).

Liquids Tax Rate = *12.25%*

Sulphur Tax Rate = *10.25%*

B. Crude Oil Freehold Mineral Tax

The tax rate for oil is expressed as follows:

Rate = 0.06 x P, when $P \leq 159\ m^3$/month

Rate = [1575 + (20 x (P - 159)] / P, when $P > 159\ m^3$/month

WHERE:

P = monthly well/tract production

3. CORPORATE INCOME TAXES

Basic Corporate Tax

The current corporate rate applicable to the first $300,000 of active business income (less the royalty tax rebate) is 4.5%. The rate applicable to taxable income over $200,000 is 13.5%. The royalty tax rebate is the disallowed Crown royalty less the 25% Resource Allowance. The rebate can either increase or decrease the tax on a corporate basis.

Royalty Tax Credits and Workover Incentives

A $30,000 production tax credit is available for wells drilled and completed on freehold land by February 29, 2004.

1. ROYALTIES

A. Natural Gas

Recent Changes

- Alberta has implemented changes to the natural gas and natural gas liquids (NGL) royalty framework. These changes are effective from the October 2002 production month and are intended to more appropriately align Alberta's natural gas and NGL royalty regime with the marketplace.

- The Crown gas royalty formula now explicitly recognizes the quantities and netback values of all products in the gas stream. These are the in stream components (ISCs): Methane (C_1), Ethane (C_2), Propane (C_3), Butanes (C_4), and Pentanes-Plus (C_{5+}).

- The overall objective is that the Crown continues to retain a fair share of the production as royalty for Albertans, the resource owners. The royalty share is determined according to the energy content, expressed in gigajoules (GJ), and is sensitive to the current level of market prices and the vintage classification of the reserves, with adjustments for low productivity wells.

Natural Gas Royalty

- Crown royalty quantities will continue to be calculated by applying the natural gas royalty rate to the energy content of the natural gas stream (expressed in gigajoules).

- The natural gas royalty rate is the weighted average of the royalty rates for the ISC quantities in the gas from each plant. The royalty rate remains vintage sensitive.

- A distinct royalty rate is set monthly for each of the following ISC products: methane, ethane, propane and butanes. Each ISC royalty rate is price-sensitive based on a distinct par price that equals the previous month's ISC reference price. A single select price is used for these four ISCs. The pentanes-plus liquids royalty rate for the month is used for the pentanes-plus ISC royalty rate.

- A reference price is set each month for each ISC product. The reference price is the weighted average of the intra-Alberta consumption and the Alberta border exports. The ISC reference prices reflect the actual amounts paid for the ISC's as reported for natural gas sales. Each reference price is reduced by the average cost to transport the ISC to market. The transport cost differs for each ISC.

- Most Crown royalty quantities are valued at the weighted average of reference prices for the ISC quantities in the gas from each plant.

- Qualifying producers can value the Crown royalty quantities at a Corporate Average Price (CAP) that cannot be less than 90% of the Gas Reference Price. This is based on a one-time election that remains available to new producers.

Notes:

- Change: A distinct par price is now set for each of the following ISCs: methane, ethane, propane and butanes. Previously the ethane par price was equal to the natural gas par price and par prices were not set for propane and butanes. A liquids par price continues to be set monthly for pentanes-plus.

- Change: The royalty rates for propane and butanes are now price sensitive, previously propane and butanes royalty rates were a flat 30% of production.

- The price sensitive pentanes-plus royalty formula remains unchanged.

- The Department of Energy (The Department) will continue to set a Gas Reference Price monthly.

Natural Gas Liquids Royalty

- The royalty rate for liquid ethane, propane, and butanes is the same as the rate determined for each of these products as an ISC. The rate for pentanes-plus is determined by the pentanes-plus royalty formula and applies to pentanes-plus as a liquid or an ISC.

- The royalty rates for liquid ethane and pentanes-plus continue to be vintage sensitive.

- For Crown royalty, liquid ethane is valued as ISC ethane.

- Reference prices for liquid propane, butanes, and pentanes-plus continue to be based on posted Edmonton prices for these liquids.

- The low productivity well allowance (LPWA) applies to both "Old" and "New" vintages, to all ISCs, and to liquid ethane, but not to other liquids.

i. GAS ROYALTY FORMULAS AND RATES

Distinction is made between old gas and new gas, and between natural gas component - methane, ethane, propane, butane, and pentanes-plus. Alberta does not distinguish between conservation gas (solution gas produced in association with oil) and non-conservation gas.

The following presents the details of the royalty framework. The inputs and formulas used to determine the royalty rate for each product are:

Methane, Ethane, Propane, and Butane

R% = Royalty Rate for each of C_1, C_2, C_3 and C_4

= BR when PP ≤ SP

= [BR x SP + MR x (PP - SP)] / PP when PP > SP

= a maximum of 35 for Old methane and Old ethane

= a maximum of 30 for New methane, New ethane, propane, and butane

WHERE:

BR = Base Rate = 15

MR = Marginal rate = 40

SP = Select Price ($/GJ). See table below.

PP = Par Price ($/GJ) = previous month's reference price.

J = Joule (a unit which expresses quantity of energy).

G = Giga (prefix for 10^9).

Low Productivity Well Allowance for ISC's

Gas wells producing at less than 16.9 $10^3 m^3$/day are entitled to an allowance that can reduce royalty rates to as low as 5%. Gas produced from oil wells is currently eligible for this allowance, if the oil production is less than 0.15 m^3/day. The LPWA is determined as follows:

For ISCs (C_1, C_2, C_3, C_4, and C_{5+}) the LPWA is determined as follows:

$$R\% = Rc\% - (R_M\% - 5) \times [((16.9 - ADP)/16.9)^2] \text{ when } ADP < 16.9$$

WHERE:

Rc% = The weighted average royalty rate for all ISCs as calculated before the LPWA.

R_M% = The royalty rate for methane.

ADP = Average daily gas production ($10^3 m^3$/day/well) over a month.

For Liquid Ethane the LPWA is determined as per the ISC formula with Rc% replaced by R_E%, where R_E% is the royalty rate for ethane.

Pentanes Plus

R% = Royalty Rate for C_{5+}

= BR when PP ≤ SP

= [BR x SP + MR x (PP - SP)] / PP when PP > SP

= a maximum of 50 for Old Pentanes Plus

= a maximum of 35 for New Pentanes Plus

WHERE:

BR = Base Rate = 22

MR = Marginal rate

= 50 for Old Pentanes Plus

= 35 for New Pentanes Plus

SP = Select Price ($/$m^3$). See table below.

PP = Par Price ($/$m^3$) = previous month's reference price.

Select Prices

	OLD METHANE $/GJ	NEW METHANE $/GJ	OLD ETHANE $/GJ	NEW ETHANE $/GJ	PROPANE $/GJ	BUTANES $/GJ	PENTANES PLUS $/M³
ANNUAL SELECT PRICE (2003)	0.379	1.290	0.379	1.290	1.290	1.290	46.11

Sulphur

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

ii. COST ALLOWANCES

Allowable costs are a deduction from gross royalties payable on natural gas and by-products to compensate for the costs of gathering, compressing and processing the Crown royalty share. Allowable costs are determined on the basis of:

Annual Capital Cost Allowances

Annual Capital Cost Allowances to royalty clients that own gathering, compressing and processing facilities. The capital cost allowance calculation includes a 15% return on investment;

Monthly Operating Cost Allowances

Monthly Operating Cost Allowances to all royalty clients that own gathering, compressing and processing facilities;

Annual Custom Processing Cost Allowances

Annual Custom Processing Cost Allowances to royalty clients that pay for gas gathering, compressing or processing on a fee for service basis.

For any royalty client, total cost allowances for a year cannot exceed the total value of royalty payable for that year. Excess cost allowances are not recoverable in other years.

For detailed information on cost allowances and business rules refer to the contacts listed at the end of this report.

iii. GAS PROGRAMS

Deep Gas Royalty Holiday (DGRHP)

Refer to Alberta Energy Information Letter 85-29.

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 metres. The drilling spacing unit must be wholly outside the deep gas pools as defined by the AEUB.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 metres. The royalty holiday applies until the value of the natural gas and by-products exempted equals the amount determined by a depth-base schedule (see table below). The maximum value is $3.6 million. Entitlements must be used within 10 years of completing drilling.

DEPTH (METRES)	CUMULATIVE VALUE ($000)	INCREMENTAL VALUE ($/ METRE)
2,500	0	1,000
3,000	500	1,000
3,500	1,000	1,000
4,000	1,500	1,300
4,500	2,150	1,300
5,000	2,800	1,600
5,500	3,600	-

Otherwise Flared Solution Gas Royalty Waiver Program (OFSG)

Refer to Alberta Energy Information Letter 99-19.

The OFSG program was introduced to encourage the reduction of solution gas flaring in Alberta. For wells approved under this program, royalty is waived on solution gas and gas by-products that are uneconomic to conserve.

Benefits

Royalty is waived on solution gas production from wells approved for OFSG status by the EUB. The EUB may determine that a portion of the solution gas production is economic to conserve. In these cases, an apportionment factor (A-factor) will be used to determine the applicable royalty waiver. For example, a .20 A-factor provides the OFSG royalty waiver to 20% of processed gas and gas by-products. All wells that were pre-approved for benefits have the A-factor set to 1.000.

Eligibility

Conventional oil wells may qualify for OFSG benefits as follows:

PRE-APPROVAL PROCESS

Wells attached to batteries that had an established history of flaring up to the end of November 1998 were automatically approved for the OFSG program.

Royalty waived status for pre-approved wells is effective January 1, 1999. Wells approved under the application based process have royalty waived status granted effective the first day of the production month the application is received. The waiver will last for a maximum period of ten years from the first production period in which the OFSG status was granted. The OFSG royalty waiver may be terminated if the average nominal gas production from the well event exceeds 15,000 m^3 per day for three consecutive months.

Application Process

For wells excluded from the automatic approval process, the battery operator must submit an application to the Department. The application must include an economic evaluation of flare gas conservation based on the economic parameters outlined in Section 2.4 of the EUB Upstream Petroleum Industry Flaring Guide G-60. The Department will forward the application to the EUB for assessment of the economic information.

Non Qualifying Wells

Natural gas wells and bitumen wells are not eligible.

Energy Efficiency Credit Program (EECP)

Refer to Alberta Energy Information Letter 2001-34.

The Energy Efficiency Credit Program encourages gas plant cogeneration by sharing in the up-front costs of cogeneration through a royalty credit.

Benefits

The royalty credit is calculated as the net present value of forecast operating cost savings to the Crown for the first 120 months after the cogeneration start-up month. The credit is based on electricity cost savings only, not steam process cost savings. The credit will account for electricity used in on-site processing as well as power wheeled to off-site plants under direct sales or contract for differences arrangements. The discount rate will be the long term Alberta Government bond rate in effect in month the application was received.

Eligibility

The program is available for the following types of cogeneration units:

- A dedicated cogeneration plant that primarily uses products obtained from natural gas processed at the gas plant, as a fuel to produce electric energy concurrently with steam for delivery to the gas plant;

- A cogeneration plant that produces electric energy for delivery to a gas plant using waste energy produced by the gas plant.

Application Process

The gas plant operator may apply for the EECP by submitting a letter application after receiving approval under Alberta's Hydro and Electric Energy Act to build a cogeneration facility. An application for credits must be made within the 6-month period following the month in which the dedicated cogeneration plant commenced operation or within any extension of that period granted by the Minister of Energy.

Sulphur Emission Control Assistance Program (SECAP)

Refer to Alberta Energy Information Letter 99-19.

Gas producers may apply for a SECAP royalty credit equal to 50% of the costs for eligible sulphur removal facilities. These facilities include, but are not limited to, sulphur recovery equipment such as klaus, direct oxidation and recycle selectox. A scheme for subsurface injection of acid gas or the transportation of acid gas to another plant for sulphur recovery is also eligible.

There are 2 categories of eligible gas plants:

SMALL GAS PLANTS (sulphur inlet rate of 1-5 tonnes per day)
To qualify for capital and operating cost assistance under SECAP, a gas processing plant must utilize an eligible process approved after July 6, 1988 and have a sulphur equivalent inlet rate of 1 to 5 tonnes per day. An eligible process is one approved by the EUB and which will achieve a minimum sulphur recovery of 70%.

LARGE GAS PLANTS (sulphur inlet rate in excess of 5 tonnes per day)
To qualify for capital cost assistance under SECAP, an eligible gas plant must utilize an eligible process and have a sulphur equivalent inlet rate in excess of 5 tonnes per day. An eligible gas plant is a sour gas plant approved before July 6, 1988. An eligible process is one approved by the EUB that achieves the phased-in sulphur recovery criteria established by the EUB in Interim Directive 2001-3, Section 3.1. In addition, eligible capital costs must increase sulphur recovery and be incurred between May 1, 2001 and April 30, 2006.

CO_2 Projects Royalty Credit Program

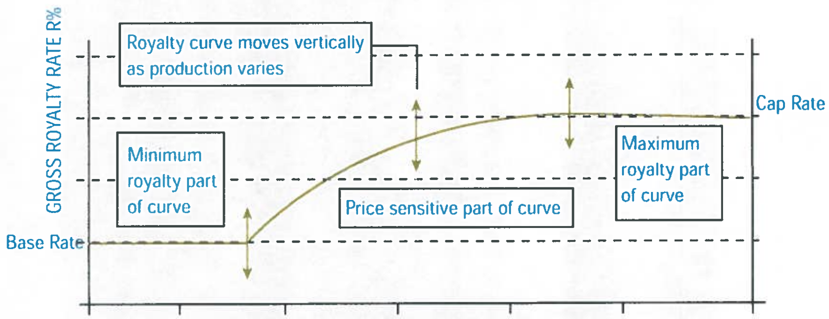
The Department of Energy has introduced this royalty reduction program as an early action to promote development of a carbon dioxide (CO_2) enhanced oil/gas recovery industry in Alberta. Royalty credits may be applied against the payment of petroleum or natural gas royalty owing to the Crown. Refer to the Alberta Enhanced Oil Recovery Section for a full description of eligibility criteria and benefits.

B. Oil

Objective:

To determine a royalty share to be retained by the resource owner that is sensitive to crude oil price and quality, well productivity and oil pool classification. The parameters of the royalty formula are set at a reference well rate of 572.1 m^3/month. At this well production rate, the base rate is 10% and the marginal rate is 40%. The following graph depicts the general form of the royalty curve.

Figure 3: Royalty Rate vs. Crude Oil Par Price



i. OIL ROYALTY FORMULAS AND RATES

Distinction is made between old oil, new oil, third-tier oil, and heavy oil.

R% = Royalty rate

R% = [BR x B + MR x (A - B)] / A x 100

WHERE:

BR = Base Rate (see Production Sensitive Royalty)

MR = 4 x BR

A = Par Price (see Price Sensitive Royalty)

B = Select Price (see Price Sensitive Royalty)

Price Sensitive Royalty

The royalty rate is price sensitive within the following ranges:

Old Oil: for A > B and A < (6 x B)

New Oil: for A > B and A < (3 x B)

Third Tier Oil: for A > B and A < (2 x B)

Par And Select Prices

Separate par and select prices are set for non-heavy and heavy oils for determining royalty rates. Select prices are set annually and par prices are determined each month.

A = par price in $/$m^3$ = average Wellhead price

B = select price in $/$m^3$

Old Oil (Pre-April 1974)

B = $28.44/$m^3$ for both non-heavy and heavy oil for 2003

New Oil (Post-march 1974)

B = $90.63/$m^3$ for non-heavy oil for 2003

B = $61.13/$m^3$ for heavy oil for 2003

Third Tier Oil (Post-September 1992)

B = $130.09/$m^3$ for both non-heavy and heavy oil for 2003

Minimum Royalty

A minimum royalty applies when the par price is less than the select price. In this case the royalty formula is

R% = BR x 100.

Maximum Royalty

A maximum royalty applies when the par price reaches a certain limit. This maximum royalty differs for each classification.

Old Oil: *R% = BR x 3.5 x 100 when A > (6 x B)*

New Oil: *R% = BR x 3.0 x 100 when A > (3 x B)*

Third Tier Oil: *R% = BR x 2.5 x 100 when A > (2 x B)*

NOTE: At certain prices and at the same production level, the royalty rate for heavy oil may exceed the non-heavy rate. If this occurs, the rate is capped at the non-heavy rate.

Production Sensitive Royalty

Production sensitivity is given to the royalty formula through the base rate (BR)

$BR = S / Q$

WHERE:

S = *the basic royalty in* m^3

Q = *monthly well production in* m^3

OLD AND NEW OIL:

$S = Q^2 / 2755.04$ when $Q < 190.7\ m^3/month$

$S = 13.2 + [(Q - 190.7) \times .115385]$ when $Q \geq 190.7\ m^3/month$

THIRD TIER OIL:

$S = 0$ when $Q < 20\ m^3/month$

$S = (Q - 20)2 / 2207.46$ when $20 < Q < 190.7\ m^3/month$

$S = 13.2 + [(Q - 190.7) \times .115385]$ when $Q > 190.7\ m^3/month$

Low Productivity Wells

Wells producing at rates of less than 190.7 m^3/month benefit from lower royalties. Third tier wells producing at rates of less than 20 m^3/month pay no royalty.

Simplified Royalty Calculation

A simplified version of the royalty formula is available for calculation of royalty liability. Required variables are reported monthly in Alberta Energy Information Letters (refer to contacts listed at the end of this report to obtain more information).

Royalty Payment

Of the regimes described in this report, Alberta's crude oil royalty regime is the only one that takes royalty in kind. Crown royalty volumes are delivered to agents on Alberta's behalf and the proceeds from their sale remitted to the Crown.

ii. OIL PROGRAMS

1. Drilling Programs

THIRD TIER EXPLORATION OIL ROYALTY HOLIDAY
Refer to Alberta Energy Information Letter 93-8.

Benefits

A royalty holiday on the first 12 production months or $1,000,000, valued at par price, is applied to the combined production from the entire exploratory interval of the well, regardless of the number of drilling, deepening or completion events.

Qualifying Wells

A third tier exploratory well is an oil or oil sands well spudded after September 30, 1992. It is classified by the AEUB as a New Field Wildcat (NFW), New Pool Wildcat (NPW) or Deeper Pool Test (DPT). The exploratory interval in an NFW and NPW well is the interval that extends from the surface to total depth. In a DPT well, the interval identified by the AEUB as exploratory extends from the base of the deepest established pool to total depth. The third tier exploratory oil produced from the exploratory interval in a well qualifies for the holiday.

Non-qualifying Types Of Wells

A Development well is a well that is not an exploratory well. If a Development well, Outpost well or Shallow Pool Test finds a new pool, the pool is classified as third tier oil, but does not qualify for a 1 year holiday.

2. Horizontal Well Royalty Programs

HORIZONTAL RE-ENTRY OIL ROYALTY REDUCTION
Refer to Alberta Energy Information Letter 93-4.

Benefits

The royalty rate will be capped for oil produced from an eligible horizontal extension. The cap will be the royalty rate associated with the average production volume for the latest 12 months when production occurred before re-entry. For a well with a 12-month production average of up to 184 m^3/month, royalty will be capped at one half that rate for the incremental production that exceeds the qualifying average. For program purposes, the average 12 -month qualifying production is referred to as the "maintenance volume".

Qualifying Types Of Wells

The following criteria must be met:

- A horizontal wellbore was drilled from an existing wellbore to extend at least 100 metres beyond the point where the wellbore deviates 80 degrees from vertical.
- The horizontal drilling activity started on or after October 1, 1992, and at least 5 years after the finished drilling date of the existing wellbore.
- The average of the 12 latest months with production establishes the "maintenance volume" for a well from a pool. These production months occurred both within the year of re-entry and the previous 4 years.

- For an injector well that is converted to a producing well by re-entry, the maintenance volume is established by the latest 12 months in which the well produced. If the well does not have 12 months of production during the year of re-entry plus the 4 previous years, the maintenance volume will be based on the 12-month average for the well(s) where production was enhanced by the injected substance (e.g., the four producing wells in a five-spot pattern).
- Production obtained through the horizontal extension is from the same pool as the maintenance volume.
- Application to the Department is filed by the well operator.
- Notification of qualification is issued by the Department.

Exclusions

A well is excluded from qualifying during the period in which one of the following circumstances is in effect:

- royalty for the well event is calculated under another;
- a well is within a Petroleum Royalty Regulation, Section 11, EOR scheme boundary or 0.8 kilometres beyond; or
- royalty is reduced under Petroleum Royalty Regulation, Section 10.

The horizontal re-entry well royalty reduction terminates when the well qualifies as either a low-productivity well or becomes a reactivated well, unless the benefits under these regulations are revoked by the Department.

3. Enhanced Oil Recovery (EOR) Royalty Relief

Refer to Alberta Energy Information Letter IL 2003-16

The Alberta enhanced oil recovery royalty regime facilitates the use of EOR methods for conservation of petroleum resources. The Enhanced Recovery of Oil Royalty Reduction Regulation provides for Crown sharing in the incremental costs of enhanced oil recovery through a reduction in royalties on incremental tertiary production.

The allowable EOR costs are incremental to the base case recovery scheme and approved by the Department of Energy. The major cost categories are as follows:

- Capital
- Consumed Energy
- Injectant
- Breakthrough Processing Allowance
- Transportation
- Overhead Allowance

Tertiary revenues are determined by a tertiary factor, which deems a portion of the oil recovered from a scheme as incremental tertiary production. The tertiary (t) factor is the lesser of 0.9 or the result of the following formula:

$$t\ Factor = \frac{\textit{incremental tertiary reserves over scheme life}}{\textit{remaining recoverable reserves at start of tertiary flood}}$$

The reduction in oil royalties is the lesser of:

- (Scheme allowed costs) x (crown interest) x (royalty rate), and,
- (Scheme oil production) x (crown interest) x (royalty rate) x (t factor) x (oil par price).

The Department of Energy evaluates each application for royalty reduction in consultation with the EUB. The key criteria for scheme approval are:

1. The scheme must receive technical approval from the EUB under Section 26 of the Oil and Gas Conservation Act.
2. The scheme must use the injection of hydrocarbons, carbon dioxide, nitrogen, chemicals or other material approved by the Minister.
3. The scheme is likely to produce more crude oil from the pool than could be produced under the base recovery scheme for that pool.
4. The costs to implement and operate the EOR scheme are significantly greater than the costs to implement and operate the base recovery scheme.
5. The Department may, in reviewing any schemes for approval, take into consideration whether the royalty reduction is in the public interest. Considerations may include the extent of the impact of the royalty reduction on the royalty ultimately payable on crude oil obtained from the scheme.

CO_2 Enhanced Oil Recovery

Alberta's Enhanced Oil Recovery (EOR) Royalty Relief program encourages the development of commercial carbon dioxide (CO_2) EOR projects. The development of a CO_2 EOR industry has the potential to provide significant long-term benefits to Alberta in the form of increased oil production and economic activity, and an increased ability to manage the province's greenhouse gas emissions via geological storage of CO_2.

The Department of Energy will provide greater royalty relief in recognition of the additional costs associated with this production method. The Department also provides some temporary features to encourage industry to undertake CO_2 EOR projects. The following changes have been implemented to the EOR Royalty Relief program effective May, 2003:

- A temporary t-factor will be provided for new and expanded CO_2 EOR projects.
- Increased allowance for recognition of the value of net CO_2 injection for EOR projects.
- Recognition of capital costs for replacement of oil field facilities associated with CO_2 injection operations.
- Increased overhead allowance to provide recognition of incremental operating costs resulting from CO_2 injection operations.

4. Research and Development Programs

CO_2 PROJECTS ROYALTY CREDIT PROGRAM

Refer to Alberta Energy Information Letter IL 2003-17

The Department of Energy has introduced this royalty reduction program as an early action to promote development of a carbon dioxide (CO_2) enhanced oil/gas recovery industry in Alberta. Alberta believes that a producer's ability to undertake certain projects is often limited by the related technical and financial risk. This new program provides a reduction in royalties to offset some financial risk to encourage producers to undertake demonstration projects.

The development of a CO_2 enhanced oil and gas recovery industry has the potential to provide significant long-term benefits to Alberta in the form of increased petroleum production and economic activity. Also, an increased ability to manage the province's greenhouse gas emissions via geological storage of CO_2.

The royalty credit program is a temporary feature of Alberta's royalty system. It has the following main attributes:

- A maximum of $15 million will be provided over five years in the form of oil and/or natural gas royalty credits to offset up to 30% of companies' approved costs in approved CO_2 projects.
- A maximum of $5 million in royalty credits may be approved for a single CO_2 project.
- Approval of applications will be constrained by total program funding, time limit for the program, and project selection criteria.
- The royalty credit is not ring-fenced to production from the project site. Royalty credits may be applied against the payment of petroleum or natural gas royalty owing to the Crown.
- The royalty credit can be claimed periodically upon commencement of CO_2 injection, as expenses are incurred, without awaiting production from the project site.

Experimental Conventional Oil Projects

Refer to Alberta Energy Information Letter 92-8.

Experimental oil projects approved by the AEUB are eligible for a flat royalty rate of 5% of production.

5. Other Crude Oil Royalty Programs

REACTIVATED OIL WELL HOLIDAY

Refer to Alberta Energy Information Letter 93-3.

Benefits

The royalty holiday is available from the reactivation date until 8,000 m^3 have been produced in aggregate from the reactivated well. Production of crude oil or oil sands from all events in the reactivated well is exempt from Crown royalty that would otherwise be payable under the Petroleum Royalty Regulation or the Oil Sands Royalty Regulation, 1997. Production from each producing event of an eligible reactivated well that has retained Old Oil status will be certified as New Oil after the well reaches the 8,000 m^3 production limit. An application is not required to qualify for the program.

Qualifying Type of Wells

A reactivated well is an oil or oil sands well that was reactivated on or after October 1, 1992, after the well did not produce any substance during its qualifying period. This period comprises the 12 consecutive months preceding the month in which reactivation took place, if that month was October, November or December 1992 or January 1993. If the well was reactivated in February 1993 or later, the period consists of the preceding 24 months. Eligible oil from a reactivated well is oil or oil sands obtained from a pool or oil sands deposit that was penetrated by the well at the time the well commenced reactivated production. Production from deeper pools or deposits penetrated after the well commenced or resumed production is not eligible.

Non-Qualifying Wells

Wells eligible for benefits under another royalty reduction program will not qualify for both benefits. Wells in enhanced oil recovery projects or eligible for an oil sands agreement or experimental royalties will be specifically excluded.

Low Productivity Oil Wells

Refer to Alberta Energy Information Letter 93-2.

Benefits

For the first 16,000 m^3 of gross oil or oil sands production from each eligible well, the royalty rate will be the lower of 5% or the rate determined by the oil royalty formula. An application is not required to qualify for the program.

Qualifying Types of Wells

- Oil well or oil sands well.
- The well did not produce more than 121 m^3/month of oil or oil sands in any month during the qualifying period.
- The qualifying period consists of the 12 consecutive months that end in September, October, November or December 1992, or the 24 consecutive months ending in January 1993 or later.
- Average monthly production for the well is 73 m^3 or less during the most recent 6 months that the well produced, providing those months occurred within the qualifying period.
- Eligible oil from a low-productivity well is oil or oil sands obtained from a pool or oil sands deposit that was penetrated by the well at the end of the well's qualifying period. Production from deeper pools or deposits penetrated after the well's qualifying period is not eligible.

C. Gas from Coal

Gas production from coal seams in Alberta falls under the Natural Gas Royalty Regulations and is treated no differently than methane production under this regulation.

D. Oil Sands

Background

In 1993, industry and government formed the joint National Task Force on Oil Sands Strategies. In the spring of 1995, the Task Force released a comprehensive report detailing its recommended royalty and tax terms for the oil sands industry in Alberta. The Task Force recommended that this regime be established by legislation rather than through individual Crown agreements. On November 30, 1995, Premier Ralph Klein announced that a generic royalty regime would be developed for Alberta's oil sands. This generic regime became effective on July 1, 1997 when the Oil Sands Royalty Regulation, 1997 was put into force.

Objectives

The objectives of the royalty regime are as follows:

- To optimize the sustained contribution from Alberta's resources in the interests of Albertans.
- To establish a single, clear and stable royalty regime that is applicable to all new investments in oil sands and facilities development without the Province of Alberta having to provide grants, loans or loan guarantees or become directly involved in any capacity other than as resource owner.
- To ensure that oil sands development in Alberta is generally competitive with other petroleum development investment opportunities around the world.

Legislation

To achieve these objectives, the Crown amended the Mines and Minerals Act, May 1997, embedding royalty formulas and the applicable return allowance rate in the Act itself.

The Oil Sands Royalty Regulation, 1997 (AR 185/97), outlines the main administrative provisions, most notably the following areas:

- requirements for project approval;
- royalty based on revenue minus costs;
- definition of allowed costs; and
- reporting and payment mechanisms.

KEY FEATURES OF THE OIL SANDS ROYALTY REGULATION, 1997

Project Approval

The generic oil sands royalty regime determines royalty on a project basis, and applies to all new investment in the oil sands whether they are new projects or expansions of existing projects. In order to become approved under the Regulation, a project must be appropriate for business and economic reasons. The Department will also assess a proposed project application, expansion, or amalgamation, to ensure any royalty impact does not leave the Crown disadvantaged. In addition, each component of the project must have an approval from the Alberta Energy and Utilities Board, share common management, and be in reasonably close geographic proximity. Projects that do not meet these requirements and are not granted an approval, projects that do not make an application under the Regulation, are subject to conventional oil royalty rates.

As a minimum, a project's output for royalty purposes is the first marketable oil sands product produced, which is *cleaned crude bitumen*. Any facilities or equipment beyond those required to produce cleaned crude bitumen must be identified by the project owner and approved by the Department before being included in the project for royalty purposes.

Royalty

The Regulation is based on a *revenue minus cost regime*. Prior to the time the project reaches payout (i.e. the developer has recovered all allowed costs, including a return allowance on those costs), the applicable royalty is 1% of the gross revenue of the oil sands project. After a project reaches payout, the Crown's royalty share (quantity) calculation is equal to the greater of:

a) 1% gross revenue for the period; or

b) 25% net revenue for the period.

For an oil sands project, the project revenue is the sum of all quantities of oil sands products from the development area multiplied by their respective unit prices. The unit price, calculated at the royalty calculation point, is:

Unit Price = (TC - HC) / TD

WHERE:

TC = the total consideration received for the oil sands product.

HC = all handling charges, export charges, pipeline tariff charges, terminal charges, processing charges, etc. paid to move the oil sands product from the royalty calculation point to the point of sale.

TD = the total quantity of the oil sands product.

In calculating the Crown's royalty share, gross revenue for a project deducts the cost of diluent contained in any blended bitumen. Revenue generated from other sources is called "other net proceeds" and reduces allowed costs.

Allowed Costs

In determining net revenue for royalty purposes, directly related expenses may be deducted as allowed costs. Costs incurred up to three years prior to the effective date of the project (related to the project's approval) are included as part of recoverable costs for the project owner.

To be eligible, an allowed cost must be:

- directly attributable to the project.
- reasonable under the circumstances.
- incurred by or on behalf of the project owners.
- incurred on or after the effective date of the project.
- incurred to recover, purchase, process, transport, market, conduct research, or provide services for oil sands products.

A return allowance is earned on the balance of cumulative costs less cumulative revenues and is set at the Government of Canada long-term bond rate (LTBR). All allowed cash costs (operating and capital) of the project are 100% deductible in the year in which they are incurred. After a project reaches payout, the return allowance is also provided on any net losses incurred by a project during a period.

Reporting and Payment Mechanisms

The Regulation outlines the reporting required by approved projects. The type of report is dependant upon the project being in pre- or post-payout, as well as the time being reported.

Pre-payout projects must submit monthly reports indicating royalty calculation and payment, as well as sales volume, sales revenue, and sales price. The latter must contain handling charges, diluent volume and price, and crude bitumen net sales volume and net price if applicable. In addition to monthly reports, a pre-payout project must submit a detailed summary of operations at the end of each period. The End of Period Statement contains the following schedules:

- Auditor's Letter
- Project Payout Status
- Allowed Costs
- Return Allowance
- Revenue
- Royalty
- Royalty Detail

Post-payout projects are also required to submit monthly royalty calculation and payment reports. In addition, a post-payout project must submit a monthly Good Faith Estimate (GFE). The GFE provides a more detailed financial record for each month of the period; actual figures for past months and estimated figures for future months. The reports required at the end of each period for a post-payout project are similar to those required for pre-payout projects, however, in addition to those necessary for a pre-payout project, schedules for Other Net Proceeds, Royalty Payable and Royalty Calculations, Revenue Detail, and Carry Forward Amounts are also required.

Regardless of payout status, in addition to monthly and end of period reports, each project is required to submit an Operator's Forecast Report for the purpose of estimating royalty revenues for the current calendar year plus the next four calendar years.

2. FREEHOLD TAXES

A. Natural Gas Freehold Mineral Tax

The freehold mineral tax levied on the holder of a natural gas right is the aggregate of field gas factors (FGF) and gas well condensate factors (GCF) calculated for each well on the basis of production.

FMT = *FGF + GCF*

FGF = *R x M x V x T when ADP* $\geq$ *16.9* 10^3m^3*/day*

FGF = *M x V x A x T when ADP* < *16.9* 10^3m^3*/day*

WHERE:

ADP = *Average daily production*

R = *Prescribed tax rate = 0.069*

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

M = *Annual field gas production* (10^3m^3*/year*)

T = *% of field gas recovered attributable to the mineral right owner*

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

GCF = *Gas Well Condensate Factor*

= *R x M x V x T*

WHERE:

Q = *Production* (m^3*/year*)

R = *Prescribed tax rate = 0.269*

M = $(0.0833 \times Q)^2 / 105.94$ *when Q* < *2,288.4* m^3*/year*

M = $(Q / 4) - 228.84$ *when Q* $\geq$ *2,288.4* m^3*/year*

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

T = *% of total production attributable to the mineral right owner*

B. Crude Oil Freehold Mineral Tax

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.

FMT = *COF + SGF*

COF = *R x M x V x T*

WHERE:

R = *Prescribed tax rate = 0.269*

M = $(0.0833 \times Q)^2 / 105.94$ *when Q* < *2,288.4* m^3*/year*

M = $Q / 4 - 228.4$ *when Q* $\geq$ *2,288.4* m^3*/year*

Q = *Production* (m^3*/year*)

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

T = *% of total production attributable to the mineral right owner*

SGF = *R x M x V x T*

WHERE:

R = *Prescribed tax rate = 0.069*

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

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

T = *% of total production attributable to the mineral right owner*

3. CORPORATE INCOME TAXES

Basic Corporate Tax

The current corporate income tax rate is 12.5% of the amount taxable in Alberta

WHERE:

Alberta Taxable Income = *(Canadian Taxable Income - Royalty Tax Deduction) * (Alberta Allocation Factor)*

Royalty Tax Deduction = *(Disallowed Crown Royalties and Freehold Mineral Tax paid but not allowed as a deduction for federal income taxes)*

-(25% Resource Allowance)

Alberta Allocation Factor = $\dfrac{\textit{Taxable income in Alberta}}{\textit{Taxable income in Canada}}$

The royalty tax deduction can only reduce the tax to zero. Unused deductions can be carried forward.

Small Business Corporate Tax

The corporate tax rate is 4.5% for firms that qualify as small businesses.

Alberta Royalty Tax Credit

The Alberta Royalty Tax Credit (ARTC) provides oil and gas producers with a refundable tax credit equal to a percentage of the first $2 million in Crown royalty paid by each corporation. Effective January 1, 1995, the percentage of royalties rebated varies between 25% and 75% with the ARTC rate sensitive to the Royalty Tax Credit Reference Price (RTCRP), which includes a blend of oil and gas par prices. The ARTC rates are expressed as follows:

ARTC % = *75 when RTCRP < $100/m*^{3}

ARTC % = *75 - (2/40)* (RTCRP-100) when $100 < RTCRP < $140/ m*^{3}

ARTC % = *73 - (48/70)* (RTCRP-140) when $140 < RTCRP < $210/ m*^{3}

ARTC % = *25 when RTCRP > $210/ m*^{3}

WHERE:

RTCRP = *Oil% x APP + (Gas% x GPP x GOC)*

Oil% = *The 3 year moving average of the percentage of Alberta conventional oil and gas royalties contributed by conventional oil.*

APP = *Average par price of oil for the previous quarter*

Gas% = *The 3 year moving average of the percentage of Alberta oil and gas royalties contributed by natural gas.*

GPP = *The gas par price in $/GJ for the latest available 3 months.*

GOC = *Gas to oil conversion ratio which is set at 79.64 GJ to 1 m.*

The ARTC rate prescribed for the second quarter of 2003 is 25% based on a RTCRP of $381.21.

1. ROYALTIES

A. Natural Gas

Distinction is made between old gas, new gas, third-tier gas, and fourth-tier gas. Saskatchewan distinguishes between conservation gas (solution gas produced in association with oil) and non-conservation gas only for fourth tier gas.

Old Gas

The old gas royalty formula retains 20% of the first $35 of the price and 45% of the remaining price at a well reference rate of 250 10^3m^3/month.

New Gas

The new gas royalty formula retains 15% of the first $35 of the price and 35% of the remaining price at a well reference rate of 250 10^3m^3/month.

Third Tier Gas

The third tier gas royalty formula retains 15% of the first $50 of the price and 35% of the remaining price at a well reference rate of 250 10^3m^3/month.

Fourth Tier Gas

The fourth tier gas royalty formula retains 5% of the first $50 of the price and 30% of the remaining price at a well reference rate of 250 10^3m^3/month.

Gas Associated With Oil

Fourth tier gas royalties apply to natural gas that is gathered for use or sale and which is produced from an oil well:

- drilled on or after October 1, 2002; or
- drilled before October 1, 2002 where the gas-oil-ratio for the well for the month exceeds 3500 cubic metres of gas per cubic metre of oil.

However, only the curve portion of the fourth tier royalty formula applies (i.e. the C and D factors don't apply to fourth tier gas produced from oil wells). Gas produced from an oil well drilled before October 1, 2002 where the gas-oil-ratio for the month does not exceed 3500 cubic metres of gas per cubic metre of oil is exempt from royalty, unless the well received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

i. GAS ROYALTY FORMULAS AND RATES

Old, New and Third Tier:

R% = Royalty rate *to a minimum of 0%*

$R\% = (C \times MGP) - SRC$ when $MGP \leq 115.4\ 10^3m^3$/month

$R\% = (K - X / MGP) - SRC$ when $MGP > 115.4\ 10^3m^3$/month

Fourth Tier:

$R\% = 0$ when $MGP \leq 25\ 10^3m^3$/month

$R\% = (C \times MGP) - D$ when $25 < MGP \leq 115.4\ 10^3m^3$/month

$R\% = (K - X / MGP)$ when $MGP > 115.4\ 10^3m^3$/month

Gas Associated with Oil:

$R\% = 0$ when $MGP \leq 64.7\ 10^3m^3$/month

$R\% = (K - X / MGP)$ when $MGP > 64.7\ 10^3m^3$/month

WHERE:

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

PGP = Provincial average fieldgate price ($\$/10^3m^3$) as determined by the Saskatchewan Department of Energy and Mines, to a minimum of $\$35/10^3m^3$ for new and old gas, and $\$50/10^3m^3$ for third tier and fourth tier gas. The price is determined prior to the deduction of gas cost allowance.

SRC = Saskatchewan Resource Credit of 2.5% for third tier gas and 1% for old gas and new gas. The intent of the Saskatchewan Resource Credit (SRC) is to take into account the non-deductibility of the Saskatchewan Corporation Capital Tax Resource Surcharge. The SRC does not apply to fourth tier gas.

K, X AND C FACTORS ARE AS FOLLOWS:

Old Gas (Pre October 1976)

$K = 26 + 32.5 \times (PGP - 35) / PGP$

$X = K \times 57.69$

$C = K / 230.76$

New Gas (Post September 1976)

$K = 19.5 + 26 \times (PGP - 35) / PGP$

$X = K \times 57.69$

$C = K / 230.76$

Third Tier Gas (Post February 8, 1998)

$K = 19.5 + 26 \times (PGP - 50) / PGP$

X = K x 57.69

C = K / 230.76

Fourth Tier Gas From Gas Wells (Post September, 2002)

$K = 6.75 + 33.73 \times (PGP - 50) / PGP$

$X = K \times 64.7$

$C = K / 205.76$

Fourth Tier Gas From Oil Wells (Post September, 2002)

$K = 6.75 + 33.73 \times (PGP - 50) / PGP$

$X = K \times 64.7$

Low Productivity Wells

The royalty formulas are production sensitive and allow royalty rates to drop to 0% for low productivity wells. For wells drilled on or after October 1, 2002, if the monthly gas production rate is 25 10^3m^3 of gas per month or less, the royalty rate is 0%.

Natural Gas Liquids Royalty

There is no royalty or tax levied on natural gas by-products (liquids) recovered at a gas processing plant. By-products contained in natural gas that is marketed in a raw (unprocessed) state are subject to the natural gas royalty/tax. Natural gas liquids that are produced and measured at the well-head are treated as crude oil for royalty purposes.

B. COST ALLOWANCES

Saskatchewan producers receive a fixed gas cost allowance of $\$10/10^3m^3$. This allowance is in recognition of costs incurred in gathering and compressing the natural gas. The costs of processing gas are excluded from the allowance because the vast majority of natural gas is dry gas that does not require further processing.

In most cases, where gas that is produced from oil wells is processed before being sold, the gas is not normally subject to royalty. In cases where the processed gas is subject to royalty, since there is no royalty on the recovered gas liquids, a higher gas cost allowance in recognition of higher processing costs is not considered.

ii. GAS PROGRAMS

Natural Gas Exploration Incentive

The first 25 million m^3 of natural gas produced from a qualified exploratory natural gas well will be subject to a maximum royalty rate of 2.5%.

To qualify, a gas well must be drilled a minimum of 4.8 kilometres from the nearest gas well or producing from a geological system below all other gas wells within 4.8 kilometres.

B. Oil

Distinction is made between old oil, new oil, third-tier oil, and fourth-tier oil.

Old Oil

The old oil royalty formula retains 20% of the first $\$50/m^3$ of the price and 45% of the remainder at a well reference rate of 100 m^3/month.

New Oil

The new oil royalty formula retains 15% (non-heavy), 12.5% (southwest) or 10% (heavy) of the first $\$50/m^3$ of the price and 35% (non-heavy and southwest) or 25% (heavy) of the price above $\$50/m^3$ at a well reference rate of 100 m^3/month.

Third Tier Oil

The third tier royalty formula retains royalty of 15% (non-heavy), 12.5% (southwest) or 10% (heavy) of the first $\$100/m^3$ of the price and 35% (non-heavy and southwest) or 25% (heavy) of the price above $\$100/m^3$ at a well reference rate of 100 m^3/month. In general, the third tier structure does not apply to horizontal wells.

Fourth Tier Oil

The fourth tier royalty formula retains a royalty of 5% of the first $\$100/m^3$ of the price and 30% of the price above $\$100/m^3$ at a well reference rate of 250 m^3/month.

i. OIL ROYALTY FORMULAS AND RATES

R = *Royalty rate*

Old Oil, New Oil And Third Tier Oil:

R% = (K - (X / MOP) - SRC) to a minimum of 0%

Fourth Tier Oil:

R% = 0 when MOP ≤ 25 m^3/month

R% = (C x MOP) - D when 25 m^3/month < MOP ≤ 136.2 m^3/month

R% = K - (X / MOP) when MOP > 136.2 m^3/month

WHERE:

MOP = Monthly Oil Production (m^3/month)

NOP = Average Wellhead price of non-heavy oil (\$/m^3) to a minimum of \$50/m^3 for old and new oil and \$100/m^3 for third tier and fourth tier oil

HOP = Average Wellhead price of heavy oil (\$/m^3) to a minimum of \$50/m^3 for new oil and \$100/m^3 for third tier and fourth tier oil

SOP = Average Wellhead price of southwest designated oil (\$/m^3) to a minimum of \$50/m^3 for new oil and \$100/m^3 for third tier and fourth tier oil.

X = K x 23.08 for old oil, new oil and third tier oil

X = K x 75 for fourth tier oil

C = K/247.8

D = K/9.9

NOTE: The SRC does not apply to fourth tier oil.

Old Oil (Pre-1974)

K = 26 + 32.5 x (NOP - 50) / NOP

New Oil (Post-1973)

K = 13 + 19.5 x (HOP - 50) / HOP for heavy oil

K = 16.25 + 29.5 x (SOP - 50) / SOP for southwest designated oil

K = 19.5 + 26 x (NOP - 50) / NOP for non-heavy oil

Third Tier Oil (Post-1993)

K = 13 + 19.5 x (HOP - 100) / HOP for heavy oil

K = 16.25 + 29.5 x (SOP - 100) / SOP for southwest designated oil

K = 19.5 + 26 x (NOP - 100) / NOP for non-heavy oil

Fourth Tier Oil (Post September 2002)

K = 7.14 + 35.71 x (HOP - 100) / HOP for heavy oil

K = 7.14 + 35.71 x (SOP - 100) / SOP for southwest designated oil

K = 7.14 + 35.71 x (NOP - 100) / NOP for non-heavy oil

Low Productivity Wells

Wells producing old oil, new oil, or third tier oil at rates less than about 23 m^3/month and wells producing fourth tier oil at rates less than 25 m^3/month pay no royalty.

ii. OIL PROGRAMS

1. Drilling Programs

Vertical Oil Well Volume-based Drilling Incentive

Certain vertical oil wells drilled on or after October 1, 2002 qualify for a reduced royalty rate of 2.5% on a fixed volume of oil produced from the well. Depending on the classification of the well, the fixed oil volumes that qualify for the incentive are as follows:

Non-Deep Vertical Exploratory Well	4,000 m^3
Deep Vertical Development Well	8,000 m^3
Deep Vertical Exploratory Well	16,000 m^3

WHERE:

Deep = producing from a zone deeper than 1,700 metres and within the Mississippian or from a zone deposited before the Bakken zone, regardless of the depth.

Exploratory = located at least 3 kilometres from the nearest oil well or producing from a geological system below all other oil wells within 3 kilometres.

Development = any well other than an exploratory well.

2. Horizontal Well Royalty Programs

Horizontal Oil Well Volume-based Drilling Incentive

All horizontal oil wells drilled on or after October 1, 2002 qualify for a reduced royalty rate of 2.5% on a fixed volume of oil produced from the well. Depending upon the depth of the well, the fixed oil volumes that qualify for the incentive are as follows:

Non-Deep Horizontal Oil Wells	6,000 m^3
Deep Horizontal Oil Wells	16,000 m^3

WHERE:

Deep = *producing from a zone deeper than 1,700 metres and within the Mississippian or from a zone deposited before the Bakken zone, regardless of the depth.*

Non-Deep = *any horizontal well other than a deep horizontal well.*

Following production of the incentive volume, oil production from all horizontal oil wells drilled on or after October 1, 2002 is subject to the fourth tier oil royalty rates, except for incremental oil from EOR projects, which is subject to the EOR royalty rates.

3. Other Crude Royalty Programs

New or Expanded Waterflood Projects

The incremental oil production from these projects is subject to the fourth tier royalty structure. A volume incentive is not available.

OIL WELL REACTIVATION PROGRAM

Oil production from qualifying reactivated oil wells will be subject to a maximum royalty rate of 4% for a period of 5 years from the date of reactivation. The applicable new oil royalty rate will apply thereafter. Only those wells reactivated after 1993, which were shut-in or suspended during the entire 1993 calendar year, will qualify under this program.

HIGH WATER-CUT PROGRAM

Incremental oil resulting from qualifying investments made to improve the recovery rates of eligible high water-cut oil wells will receive third tier oil royalty rates with an SRC of 2.5%.

Eligible oil wells (vertical and horizontal) include:

1) Individual oil wells or a group of oil wells that are currently producing oil and have an average water-cut of 95% or greater during the last 12 months prior to making an application under the program.

2) Wells that have been shut-in or suspended for 12 or more months prior to making investments, and that produced at an average water-cut rate of 95% or greater during the last 3 producing months prior to being shut-in.

4. Enhanced Oil Recovery (EOR) Royalty Relief

The Saskatchewan enhanced oil recovery royalty regime is a cost sensitive system that recognizes the higher investment and operating costs associated with EOR projects. The EOR royalty regime applies to any project that enhances the total recovery of oil through the use of thermal recovery techniques or approved recovery techniques other than waterfloods.

Two separate royalty rate structures exist, one for carbon dioxide injection projects and the other for projects other than carbon dioxide injection projects. For either type of project, the royalty level is sensitive to project profitability and investment payout. The EOR royalty rate is calculated as follows:

	FOR CARBON DIOXIDE INJECTION PROJECTS	FOR OTHER EOR PROJECTS
Before Investment Payout	1% of Gross Revenue	Intermediate of (1% of Gross Revenue, 5% of gross Revenue, 10% of net revenue) - SRC
After Investment Payout	20% of Net Revenue	Greater of (5% of Gross Revenue, 30% of Net Revenue) - SRC

WHERE:

Gross Revenue = *the value of EOR oil production from a project. The EOR oil is determined by multiplying the total oil production from the project by the EOR factor (additional recoverable reserves/total remaining recoverable reserves). The EOR factor for heavy oil projects is 100%.*

Net Revenue = *Gross Revenue minus operating costs, in most cases.*

SRC = *2.5% of Gross Revenue for new or expanded projects commencing on or after February 9, 1998 and 1% of Gross Revenue for projects commencing prior to February 9, 1998.*

2. FREEHOLD TAXES

The freehold tax is referred to as freehold production tax in Saskatchewan.

A. Natural Gas Freehold Mineral Tax

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

PTF = *6.9 for old gas*

= *10.0 for new gas and third tier gas*

= *12.5 for fourth tier gas*

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

Eligibility of freehold gas wells for a volume-based tax reduction is determined in the same manner as the volume-based Crown royalty reduction.

B. Crude Oil Freehold Mineral Tax

Conventional Oil Production

For oil production other than for oil produced from approved EOR projects, the production tax rate is derived by subtracting a production tax factor (PTF) from the calculated royalty rate that would have applied had the production come from Crown land. The intent of the PTF is to equate after-tax netbacks between Crown and freehold production.

PTF = *6.9 for old oil*

= *10.0 for new oil and third tier oil*

= *12.5 for fourth tier oil*

EOR Oil Production

A cost sensitive production tax regime exists for freehold oil produced from approved EOR projects. As is the case with the royalty regime applicable to Crown production, the tax regime is a cost sensitive system that recognizes the higher investment and operating costs associated with EOR projects. The production tax rate, which is sensitive to project profitability and investment payout, is calculated as follows:

	FOR CARBON DIOXIDE INJECTION PROJECTS	FOR OTHER EOR PROJECTS
Before Investment Payout	0%	0%
After Investment Payout	11% of Net Revenue	23% of Net Revenue - SRC

WHERE:

Net Revenue = *Gross Revenue minus operating costs and freehold mineral owner royalties.*

SRC = *2.5% of Gross Revenue for new or expanded projects commencing on or after February 9, 1998 and 1% of Gross Revenue for projects commencing prior to February 9, 1998.*

Drilling Incentives

Eligibility of freehold oil well for a volume-based tax reduction is determined in the same manner as the volume-based Crown royalty reduction. The production tax rate on the appropriate incentive volume is reduced to 0%.

3. CORPORATE INCOME TAXES

Basic Corporate Tax

The current corporate income tax rate is 17% of taxable income earned in Saskatchewan less the royalty tax rebate. The small business rate is 8%.

The royalty tax rebate is the royalties/taxes less the 25% Resource Allowance. The rebate cannot increase the tax. Unused deductions can be carried forward.

Corporation Capital Tax Resource Surcharge

Large corporations that have more than $10 million in paid-up capital allocated to Saskatchewan are assessed a corporation capital resource tax surcharge. The surcharge is equal to the difference between the existing corporation capital tax liability and 3.6% of a corporation's value of Saskatchewan resource sales. Based on the proportion of total salaries and wages paid in Saskatchewan by the corporation and its associates, the basic $10 million exemption can be increased to $15 million. A value of resource sales deduction of up to $2.5 million is available for resource corporations whose assets total less than $100 million.

Small Business Deduction

Effective January 1, 1995, the small business corporate income tax rate was reduced to 8.0% from 8.5%.

Saskatchewan Resource Credit

Crown royalty and freehold production tax rates are eligible for the Saskatchewan Resource Credit (SRC) reduction in effect since 1988. The SRC is equal to:

- 1% for oil and gas production from vertical wells drilled before February 9, 1998 and horizontal wells drilled before October 1, 2002;
- 2.5% for oil and gas production from vertical wells drilled on or after February 9, 1998 and before October 1, 2002, new or expanded waterflood projects commencing on or after February 9, 1998 and before October 1, 2002 and new or expanded EOR projects commencing on or after February 9, 1998;

- 0% for oil and gas production from vertical or horizontal wells drilled on or after October 1, 2002 and new or expanded waterflood projects commencing on or after October 1, 2002.

Workover Incentives

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

1. ROYALTIES

A. Natural Gas

i. GAS ROYALTY FORMULAS AND RATES

Natural Gas

R% = Royalty rate

R% = 12.5% of monthly sales

Low Productivity Wells

There is no special allowance for low productivity wells.

Natural Gas Liquids

Royalties and taxes are not levied separately on natural gas by-products. The levy on raw natural gas encompasses by-products.

ii. COST ALLOWANCES

Manitoba does not have a gas cost allowance.

iii. GAS PROGRAMS

Manitoba does not offer natural gas royalty programs.

B. Oil

Distinction is made between old oil, new oil, and third-tier oil.

Old Oil

The old oil royalty formula retains between 0 and 18.9% of production for well production rates between 0 and 50 m^3/month. For well production rates between 50 and 300 m^3/month, a rate between 18.9 and 40.6% is applied.

New Oil

The new oil royalty formula retains between 0 and 10.4% of production for well production rates between 0 and 50 m^3/month. For well production rates between 50 and 300 m^3/month, a rate between 10.4 and 22.4% is applied.

Third Tier Oil

The new oil royalty formula retains between 0 and 8.9% of production for well production rates between 0 and 50 m^3/month. For well production rates between 50 and 300 m^3/month, a rate between 8.9 and 19.1% is applied.

i. OIL ROYALTY FORMULAS AND RATES

R% = Royalty rate

$R\% = [RV / P] \times 100$

$RV = [K \times P^2] / 265$ when $P \leq 50\ m^3/month$

$RV = K \times [9.43 + 0.45 \times (P-50)]$ when $P > 50\ m^3/month$

WHERE:

RV = Crown royalty volume

P = Production (m^3/month)

Old Oil (Prior To April 1, 1974)

$K = 1.00$

New Oil (On Or After April 1, 1974 And Prior To April 1, 1999)

$K = 0.55$

Third Tier Oil (On Or After April 1, 1999)

$K = 0.47$

Holiday Oil (January 1, 1987 To January 1, 2004)

$K = 0.0$

Low Productivity Wells

Wells producing at rates less than 50 m^3/month benefit from lower royalties.

ii. OIL PROGRAMS

1. Drilling Programs

MANITOBA DRILLING INCENTIVE PROGRAM

The Manitoba Drilling Incentive Program provides the licensee of new wells or qualifying wells with a royalty/tax free "holiday oil volume". No royalties or taxes are payable until the holiday oil volume has been produced. The program consists of six components: New Well Holiday Oil Volume, Deep Well Holiday Oil Volume, Horizontal Well Holiday Oil Volume (see Horizontal Well Features), Major Workover Incentive, Injection Well Holiday and the Holiday Oil Volume Account.

NEW WELL HOLIDAY OIL VOLUME (TO JANUARY 1, 2004)

New wells drilled prior to January 1, 2004, qualify for a royalty/tax free production volume. The holiday volume is sensitive to oil price and is dependent on the well's location. The maximum holiday volume is 10,000 m^3 or 10 years of production, whichever occurs first. No application is required to receive the holiday oil volume.

The holiday volume is calculated in accordance with the following equations:

If D < 2 kilometres: $HOV = A \times D + B$

If D > 2 kilometres: $HOV = A' \times D^2 + B'$

WHERE:

HOV = *The holiday oil volume in m^3 earned by the well*

D = *Distance in kilometres from the nearest well which, as of the finished drilling date of the new well, is cased for production from the same or a deeper formation penetrated by the new well.*

A = $1.7P + 230$

B = $3130 - 13.6P$

A ' = $0.17P + 106.9$

B ' = $3163 - 10.9P$

P = *Average Price ($/$m^3$) delivered to the terminal at Cromer, Manitoba during the month in which the new well is spudded.*

DEEP WELL HOLIDAY OIL VOLUME (APRIL 1, 2001 TO JANUARY 1, 2004)

Any new well drilled prior to January 1, 2004, to a depth to fully penetrate the Devonian Duperow Formation, is provided with a holiday volume of 20,000 m^3. Credits earned through previous drilling, or major workover activity can be used to increase the holiday oil volume of wells completed for production from a formation deeper that the Devonian Three Forks Formation, to a maximum of 10,000 m^3.

INJECTION WELL HOLIDAY (APRIL 1, 2001 TO JANUARY 1, 2004)

Wells drilled or converted to injection as part of an approved enhanced oil recovery project, are exempt from payment of any Crown royalty or freehold production tax for a one-year period. The exemption applies to the tracts in which the well is located, as determined under regulation. Vertical wells are to be converted to injection prior to producing 250 m^3. Horizontal wells are to be converted to injection prior to producing 1000 m^3.

HOLIDAY OIL VOLUME ACCOUNT

Each licensee of a well or wells may establish a holiday volume account. The purpose of such an account is to provide flexibility in the allocation of earned holiday volumes. This account may be used to bank and allocate holiday volumes earned by the licensee.

2. Horizontal Well Royalty Programs

HORIZONTAL WELL - HOLIDAY OIL VOLUME (UNTIL JANUARY 1, 2004)

A horizontal well (defined as a well that achieves an angle of 80 degrees from vertical for a minimum distance of 100 metres or a well that has been re-entered or recompleted that meets these criteria) drilled prior to January 1, 2004, earns a holiday volume of 10,000 m^3. This volume must be produced within 10 years of the finished drilling date.

All horizontal wells are classified as new oil wells for royalty and tax purposes. Holiday volumes earned by a horizontal well can be transferred to the licensee's holiday volume account.

3. Other Crude Oil Royalty Programs

MARGINAL WELL MAJOR WORKOVER HOLIDAY OIL VOLUME (UNTIL 2004)

Any marginal well where a major workover is completed prior to January 1, 2004, earns a holiday oil volume of 500 m^3. A marginal well is defined as a well drilled at least 12 months ago that, over the previous 12 months, has been shut in or has an average oil production rate of less than 1 m^3 per operating day.

Enhanced Oil Recovery (EOR) Royalty Relief

The Crown Royalty and Incentives Regulation and the Oil and Gas Production Tax Regulation provides for a portion of the oil produced from a new waterflood, or other enhanced oil recovery project, to qualify as third tier oil for Crown royalty/freehold production tax purposes. Third Tier Oil is defined as oil produced from a third tier oil well, an inactive well that is reactivated after April 1, 1999 or, an old oil well or new oil well that can reasonably be attributed to an increase in reserves as a result of an EOR project implemented after April 1, 1999.

A Third Tier EOR Factor is applied to old oil and new oil production from the approved project area to determine a project's Third Tier EOR Production. The Third Tier EOR Factor (TTEF) is determined by Industry, Trade and Mines, at the time of project approval, based on the following formula:

$$TTEF = \frac{\text{Incremental EOR Recoverable Reserves (IERR)}}{\text{Total Remaining Recoverable Reserves (TRES)}}$$

WHERE:

IERR (m^3) = *Incremental EOR recoverable reserves that are attributed to the approved EOR project.*

TRES (m^3) = *Total remaining recoverable reserves for the approved EOR project.*

The Third Tier EOR Factor (TTEF) is applied to the monthly old and new production from the EOR project to determine the Third Tier EOR Production (TTEP) for the project, as shown below. The project commencement date, and the date, on which TTEP begins, is defined as the first day of the month in which the project as approved is fully implemented.

TTEP = (TTEF) x (Project Old Oil Production + Project New Oil Production)

Total project production is a sum of the following volumes:

Net Old Oil Production = (1-TTEF) x (Project Old Oil Production)

Net New Oil Production = (1-TTEF) x (Project New Oil Production)

Third Tier Oil Production = TTEP + Third Tier Oil Well Production[1]

1 Third Tier oil well production includes both oil from third tier oil wells and oil from inactive wells that are reactivated after April 1, 1999.

2. FREEHOLD TAXES

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.

A. Natural gas Freehold Mineral Tax

The freehold tax is calculated as 1.2% of the volume produced or sold from a location.

B. Crude Oil Freehold Mineral Tax

The freehold tax on crude oil is calculated based on the monthly production rate and oil classification.

TR = Tax rate as % of P

P = Production (m^3/month)

Old Oil

$TR = 0$ when $P \leq 20$

$= [(0.43 \times P) - 8.24]$ when $20 < P < 65$

$= [42.76 - (1{,}500 / P)]$ when $P \geq 65$

New Oil

$TR = 0$ when $P \leq 36$

$= [(0.23 \times P) - 8.11]$ when $36 < P < 65$

$= [19.59 - (820 / P)]$ when $P \geq 65$

Third Tier Oil

$TR = 0$ when $P \leq 46$

$= 11 - (465 / P)$ when $P > 46$

Holiday Oil

$TR = 0$ for all volumes

3. CORPORATE INCOME TAXES

Corporate Tax

The current corporate income tax rate is 16% of taxable income earned in Manitoba. The small business rate is 5%.

Royalty Tax Credits And Workover Incentives

Manitoba offers a holiday volume for major well workovers. See description under "Other Crude Oil Royalty Programs".

VI YUKON

In November 1998, the Yukon Territory was transferred authority for its oil and gas resources from the federal government. Royalty regulations are under development and expected to be promulgated in 2003. Draft Regulations are available on Yukon's Website.

For further information, refer to the contacts at the end of this report.

Department of Energy, Mines and Resources
Visit the EMR website at www.oilandgas.gov.yk.ca

Oil and Gas Management Branch
209-212 Main Street
Whitehorse, Yukon, Y1A 2C6
Phone: 867-667-3427
Fax: 867-393-6262

VII NORTHWEST TERRITORIES AND NUNAVUT

On April 1, 1999, the Northwest Territories was divided, creating a new territory, Nunavut (which means "our land" in Inuktitut). Currently, the federal government manages oil and gas resources in the Northwest Territories and Nunavut. See Section VIII - Federal

1. ROYALTIES

Natural resources in Canada are owned by the Provinces; as such, royalties fall under provincial jurisdiction. However, natural resources in areas that are not provinces or not subject to special agreement (e.g., the Atlantic Accord and the Canada-Nova Scotia Offshore Accord) fall under Federal jurisdiction.

Federal royalties can be categorized as applying to:
Frontier Lands; and Reserve Lands.

Royalties on frontier lands are prescribed under the Canada Petroleum Resources Act (CPRA) while those on reserve lands come under the Indian Oil and Gas Act.

Reserve lands are held in the name of the federal Crown for the use and benefit of the respective native bands for which they were set apart. The Indian Oil and Gas Act allows for a variation in the royalty payable by entering into special agreement, with the consent of the Chief and Council. Special royalty agreements have been entered into for nearly all land dispositions since the mid 1980's. As a result, the royalty regime applicable to reserve lands is not described further.

Frontier Lands

A. Natural Gas

Under the *Canada Petroleum Resources Act* (CPRA) and the *Frontier Lands Petroleum Royalty Regulations* (FLPRR) , the royalty consists of a 1% royalty on gross revenue at start-up, increasing by 1% every 18 production months to a maximum of 5% or until payout is reached. After payout, the royalty is calculated at the greater of 30% of net profit or 5% of gross revenues.

Net profit is calculated as:

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

Operating and capital costs receive 10% and 1% uplifts respectively post project commencement to recognize indirect expenses. Allowed capital costs incurred before the project commencement receive an uplift based on the inflation index.

Prior to payout, un-recovered costs are given a return allowance equal to the long-term government bond rate plus 10%. Royalty payout is attained when cumulative gross revenues exceed cumulative operating costs, capital costs, gross royalties, paid and a return allowance. Payout is calculated on a working interest basis, by project.

Incentives - Investment Royalty Credit
New exploration wells, exploratory probes or delineation wells located on frontier lands are eligible for the Investment Royalty credit (IRC). The IRC is calculated as 25% of eligible Qualified Exploration Expense (QFEE) to a maximum of $5 million per well.

B. Oil

The royalty regime applicable to frontier lands is the same for both oil and natural gas.

2. CORPORATE INCOME TAXES

In March 2003, the Federal Government announced changes to the federal tax system that are proposed for the 2003-2007 period.

Under the proposal, the net federal tax rate will be reduced from 28% in 2002 to 21% in 2007 (these rates are net of the 10% abatement for income taxes levied by the provinces), with a 27% net tax rate applicable for 2003. The 4% federal surtax on corporate tax payable will remain in effect for an indefinite period. The capital tax for post-2002 tax years will be eliminated (large corporations were previously assessed an additional tax of 0.225% on taxable capital employed in Canada, less a capital deduction of $10 million).

Allowable Deductions

Corporations are generally allowed deductions for amounts paid out to earn income, including operating and lifting costs, capital cost allowance, interest expense, exploration and development expense, general and administrative expense and, in some cases, earned depletion. Capital cost allowance provides a deduction against income for depreciating property. Many classes of depreciable property exist, the most relevant being Class 41 for oil and gas equipment. Class 41 allows a 25% write-down of equipment on a declining balance basis.

Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expense (CEE)[1]; Canadian Development Expense (CDE)[2]; or Canadian Oil and Gas Property Expense (COGPE)[3]. The CEE balance of exploration expenditures must 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.

Under the pre-2003 tax regime, the Resource Allowance was allowed as a deduction in lieu of provincial royalties and freehold mineral taxes, which were not tax deductible. The Resource Allowance is equal to 25% of resource profits computed as gross revenue (including production royalties receivable and deemed income in B.C.) less the sum of: operating and lifting costs, non-provincial production royalties paid or payable, general and administrative expenses related to production, deductible Crown lease rentals, and capital cost allowances in respect of production assets. 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.

Commencing in the 2003 tax year, the resource allowance deduction will be phased out and a portion of crown royalties will become deductible. The transition schedule is shown below:

	2002	2003	2004	2005	2006	2007
Federal Corporate Tax Rate	28%	27%	26%	25%	23%	21%
Deductible portion of Resource Allowance	100%	90%	75%	65%	35%	0%
Deductible portion of Crown Royalties	0%	10%	25%	35%	65%	100%
Tax Rate for Other Industries	25%	23%	21%	21%	21%	21%

[1] CEE: includes geological, geophysical, geochemical, drilling and completion expenses, cost of building a temporary access road or preparing a site for the well.

[2] CDE: includes expenses incurred in drilling or converting a well for the disposal of waste liquids, injection of water, gas or other substances, monitoring fluid levels or pressure changes, drilling for water or gas for injection, drilling & completing a well after the commencement of production or drilling & completing a well, building a temporary access road or preparing a site for the well to the extent that the expense is not a Canadian exploration expense.

[3] COGPE: includes the cost of any right, licence or privilege to explore or drill for petroleum, natural gas or related hydrocarbons, the cost of any oil or gas well, and any rental or royalty.

Small Business Deduction

Canadian Controlled Private Corporations (CCPC's) may deduct 16% of a maximum of $200,000 net income. This effectively reduces the rate on the first $200,000 from 38% to 22% (before provincial abatement).

Example Of Simplified Tax Calculation Format

Gross Revenue

- *Operating & Lifting Costs*
- *Non-Crown Royalty*
- *General &s Administrative Expense*
- *Capital Cost Allowance*
- *Interest Expense*
- *Exploration & Development Expense*
- *Resource Allowance*

= ***Net Income***

x *Tax Rate*

= *Tax Payable*

Common CCA Classifications

Class 1	4%	Pipeline manufacturing & distributing gas plant equipment.
Class 2	6%	As in Class 1, but acquired before 1988 - pursuant to an obligation in writing entered into before June 18, 1987 - that is a building, structure, plant facility or other property where the property was under construction by or on behalf of the taxpayer on June 18, 1987; or - that is machinery or equipment that is a fixed and integral part of property under construction by or on behalf of the taxpayer on June 18, 1987.
Class 10	30%	As in Class 41, but before 1987 and after 1979.
Class 29	50%	As in Class 39, but before 1987
Class 39	30%	Manufacturing & processing plant and equipment or oil or water storage tank after 1987.
Class 41	25%	Gas or oil well equipment Property acquired after 1987 that is designed principally for the purpose of: • determining the existence, location, extent or quality of accumulations of petroleum or natural gas, property acquired after 1980 to be used in the processing of heavy crude oil.

IX GRAPHIC COMPARISON AMONG PROVINCES

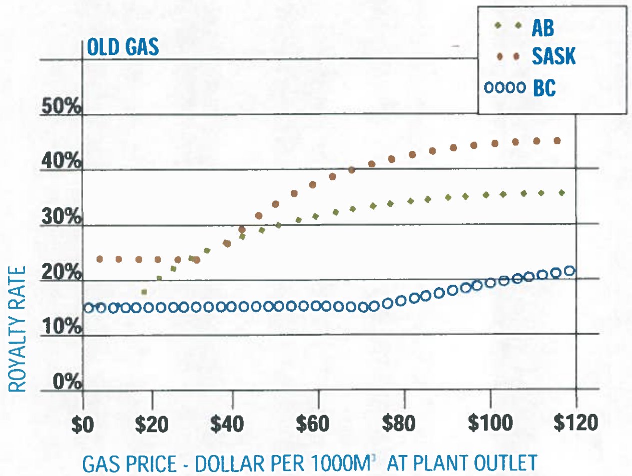
This section presents the natural gas and crude oil royalty formulas for British Columbia, Alberta, and Saskatchewan in graphic form. The graphs serve to illustrate royalty sensitivities to well productivity, date and density classification, and price.

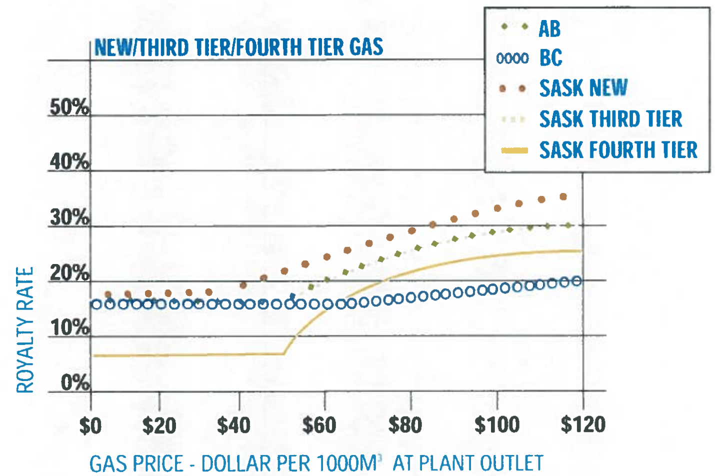
Natural Gas

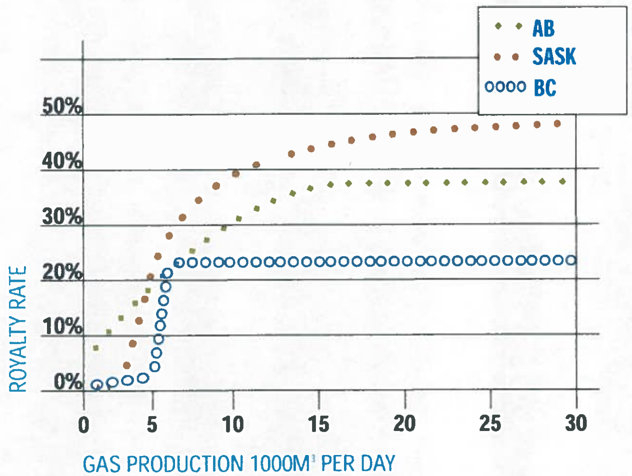
In the graphs depicting price, the well production rate is assumed to be 25 10^3m^3 per day. In the graphs depicting production, price is assumed to be \$150 per 10^3m^3. The select prices in effect for 2003 were used in the calculations.

Crude Oil

In the graphs depicting price, both heavy oil and non-heavy oil have an assumed production rate of 125 m^3 per month. In the graphs depicting production, heavy oil has price fixed at \$133/m^3, while non-heavy oil has a fixed price of \$195/m^3. The select prices in effect for 2003 were used in the calculations.







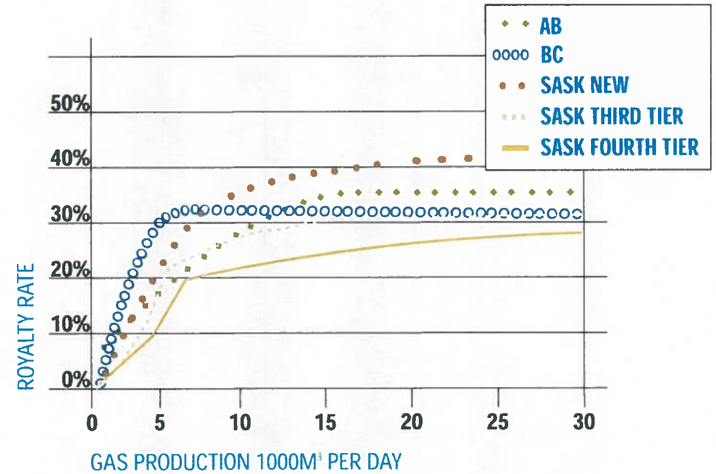
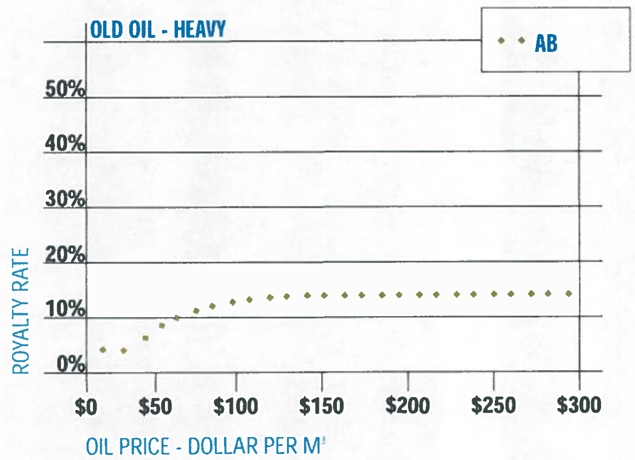
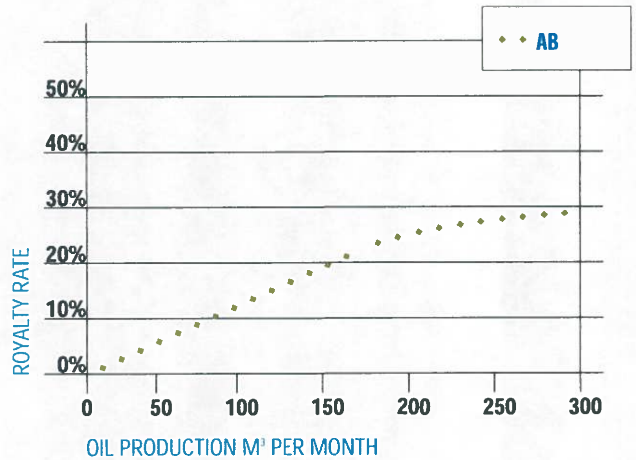
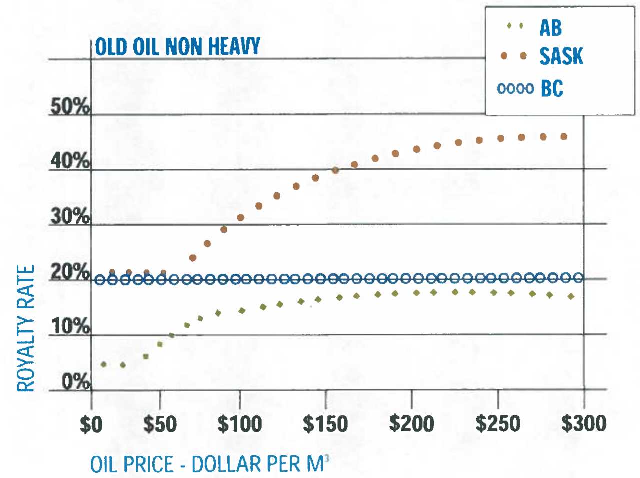


Figure 4: Natural gas royalty rates are a function of price, well productivity and classification. Note that British Columbia's curve has been adjusted to reflect gross royalties at the value of the plant inlet (Alberta and Saskatchewan value gas at the plant outlet for royalty purposes).







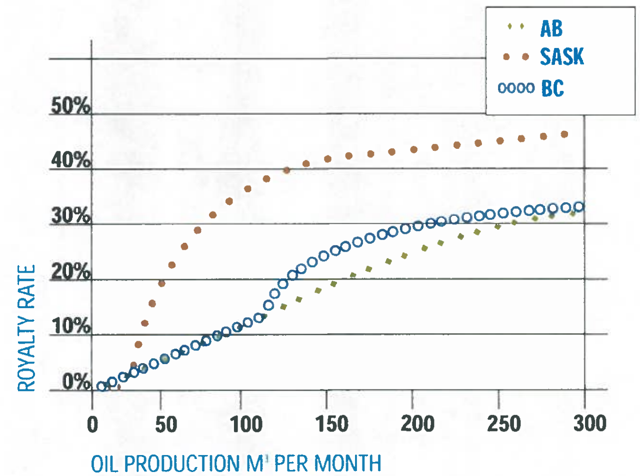
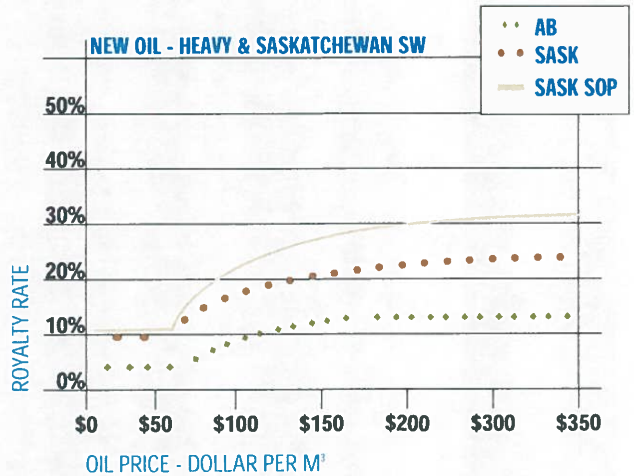
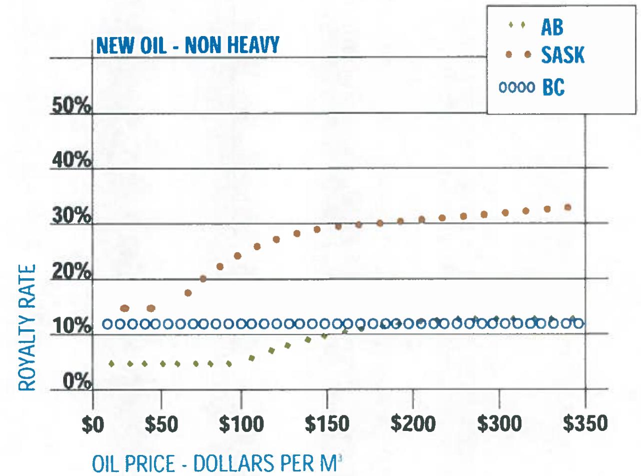
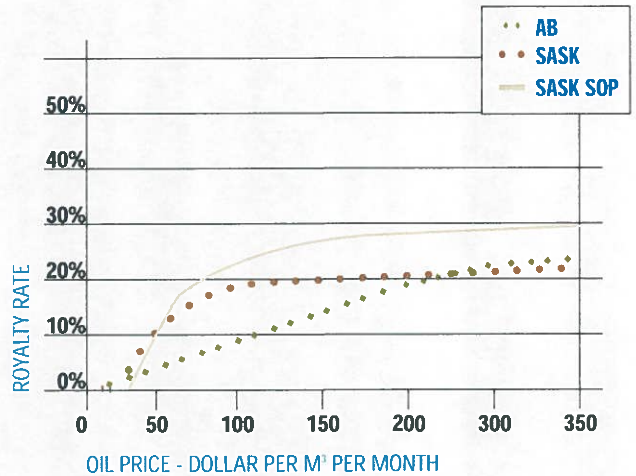


Figure 5: Old oil royalty rates are a function of oil classification and Wellhead productivity. The Alberta and Saskatchewan old oil royalty formulas also include price sensitivity. British Columbia's heavy oil formula was implemented in 1999. Although it is not date sensitive the British Columbia heavy oil formula is shown under the provincial comparison for third tier and fourth tier oil that were also implemented in more recent time frames. Saskatchewan has no heavy oil classification for old oil.







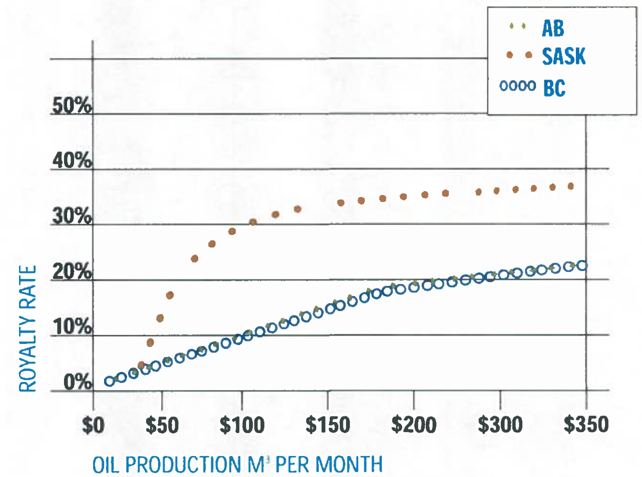
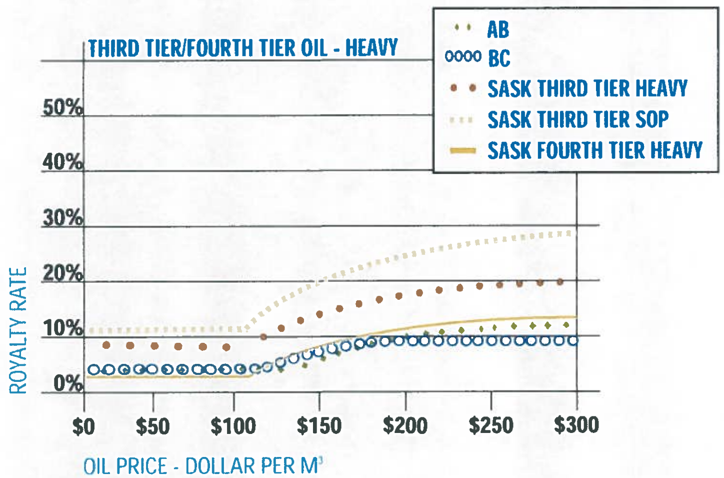
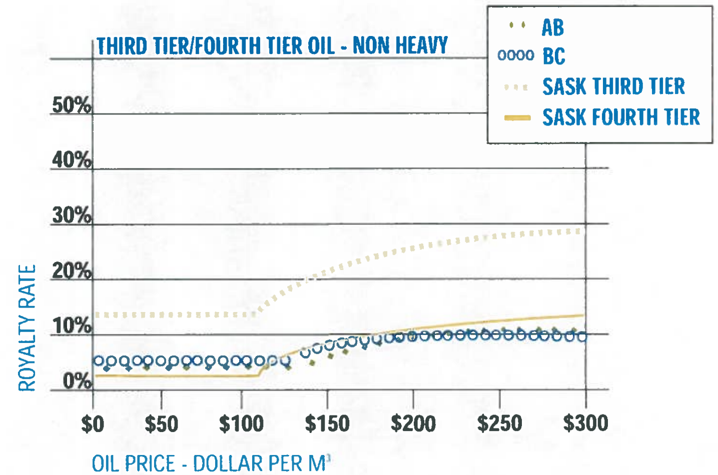
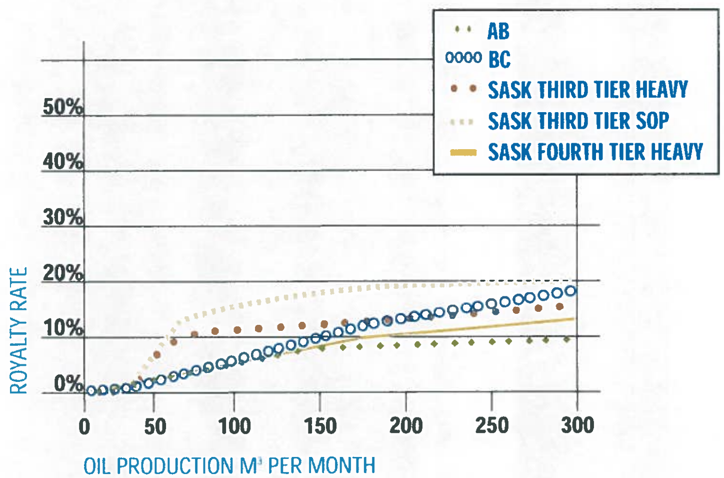


Figure 6 New oil royalty rates are a function of oil classification and Wellhead productivity. The Alberta and Saskatchewan new oil royalty formulas also include price sensitivity. British Columbia's heavy oil formula was implemented in 1999. Although it is not date sensitive, the British Columbia heavy oil formula is shown under the provincial comparison for third tier and fourth tier oil that were also implemented in more recent time frames. Saskatchewan has no heavy oil classification for old oil.







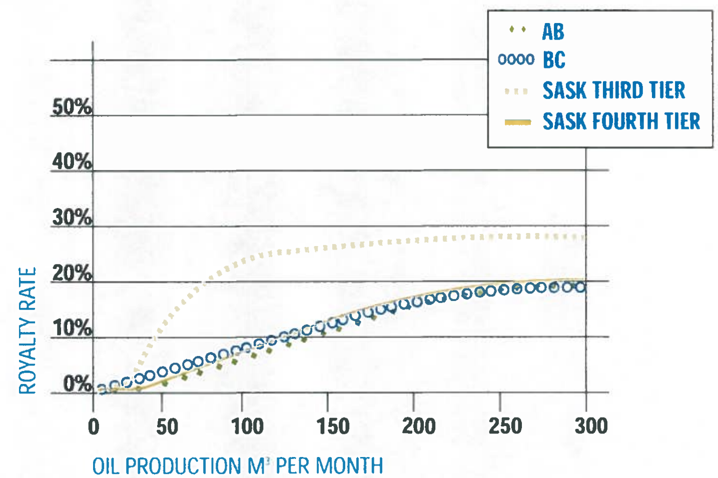


Figure 7 Third tier and fourth tier oil royalty rates are a function of oil classification, Wellhead productivity and price. Saskatchewan has separate categories for heavier crudes under third tier oil and fourth tier oil: heavy oil and southwest designated oil. The density of these categories is typically comparable to Alberta's heavy oil. As Saskatchewan's fourth tier heavy and southwest oilv royalty rates will be the same for a given Wellhead price, only the latter is shown.

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Alberta Department of Energy

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Information Centre/Library

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Gas Royalty, Cost Allowances, Gas Holidays and Relief,
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General information about the Ministry
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Oil and Gas Management Branch
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Phone: 867-667-3427
Fax: 867-393-6262

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Northern Oil and Gas Directorate - Indian and Northern Affairs Canada

Website: www.ainc-inac.gc.ca/oil/index_e.html

Northern Oil and Gas Directorate
6th Floor, 10 Wellington Street
Gatineau, Quebec K1A 0H4
Phone: (819) 953-9488 or (819) 997-0203
Fax: (819) 953-5828