Oil and Gas Fiscal Regimes

WESTERN CANADIAN PROVINCES AND TERRITORIES

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I INTRODUCTION

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.

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.

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.

NOTE: The information provided in this report 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.

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.

1) 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 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 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	wells drilled on or after February 9, 1998.
Fourth Tier Gas	wells drilled on or after October 1, 2002.
Old Oil	wells drill before 1974 (heavy oil and oil produced in the southwest area of the province was reclassified to New Oil).
New Oil	vertical wells drill after 1973 and horizontal wells drilled on or after April 1, 1991.
Third Tier Oil	vertical wells drilled after 1993 (includes incremental oil produced from new or expanded waterfloods that commence operation after 1993).
Fourth Tier Oil	wells drilled on or after October 1, 2002 (includes incremental oil produced from new or expanded waterfloods that commence operation on or after October 1, 2002).

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 major workovers of marginal wells after January 1, 2005; 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).

2) Density Classifications

BRITISH COLUMBIA

Heavy Oil	oil with density $\geq$ 890 kg/m^3
Non-heavy Oil	oil with density < 890 kg/m^3

ALBERTA

Heavy Oil	oil with density $\geq$ 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. Oil density in this area ranges from 945 to 1000 kg/m^3 with an average of approximately 975 kg/m^3.

Southwest-designated oil is oil produced from wells drilled on or after February 9, 1998 and incremental oil produced from waterfloods commencing operation on or after February 9, 1998 in the southwest area of the province. The southwest area includes the area within Townships 1 through 21 in Ranges 1 through 30, west of the third meridian. Oil density in this area ranges from 885 to 997 kg/m^3 with an average of approximately 925 kg/m^3.

Non-heavy oil is all oil other than Heavy oil or Southwest-designated oil.

MANITOBA

Manitoba does not classify its oil resources by density.

II BRITISH COLUMBIA

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, and 15% of the price in excess of $50.

R% = [400 + 15 x (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 price is 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 price is 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 x (RP - SP)] / RP (not below 12% and not more than 27%)

BASE 9 GAS

For wells on lands acquired after June 1, 1998 which are completed within 5 years of the date rights are issued, the royalty formula retains 9% of the price, when the price is 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 x (RP - SP)] / RP (not below 9% and not more 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 ($/$10^3m^3$) set by the Royalty Administrator. For 2006 and all prior years, the select price is $50.

Low Productivity Wells

A low productivity rate reduction applies for conventional natural gas wells producing less than 5,000 m^3 per day in a producing month.

R% = Rc% - Rc% x $[(5000 – ADV) /5000]^2$

Where:

Rc = Royalty percent 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

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

iii. GAS ROYALTY PROGRAMS

1. Natural Gas Royalty Reduction

Non-Conservation Gas from wells drilled on land rights acquired after June 1, 1998 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 is 9%.

2. Deep Royalty Program

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 depth of at least 2,500 metres for vertical wells and 2,300 metres for horizontal wells;

(b) the well has a spud date after June 30, 2003.

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.

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

DEEP ROYALTY HOLIDAY CREDITS

WEST SPECIAL SOUR			EAST SPECIAL SOUR		
Depth	Cumulative Value	Incremental Value	Depth	Cumulative Value	Incremental Value
Metres	$000	$/Metre	Metres	$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	$000	$/Metre	Metres	$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	-

3. Deep Re-entry Royalty Program

A deep re-entry deduction amount may be provided to a deep re-entered well if the well has a re-entry date after November 30, 2003.

The credit is defined in terms of a dollar amount applied against royalties, which increases with the incremental drilled distance, for wells that have depths of at least 2,300 metres.

WEST			EAST		
Table Distance	Cumulative Value	Incremental Value	Table Distance	Cumulative Value	Incremental Value
Metres	$000	$/Metre	Metres	$000	$/Metre
100	0	750	100	0	450
300	150	500	300	90	300
1,500	750	-	1,500	450	-

ROYALTY CALCULATION:

The deep re-entry deduction amount is calculated as:

CV + AD

Where:

CV means the Cumulative Value shown opposite the Table Distance of the deep re-entry well event.

Table Distance means the Incremental Drilled Distance applicable to the deep re-entry well event rounded down to the next lowest Table Distance value.

AD means the Incremental Value that is shown opposite the Table Distance of the deep re-entry well event multiplied by the positive difference between the Incremental Drilled Distance applicable to that deep re-entry well event and the Table Distance of that well event.

Incremental Drilled Distance means the positive difference between the total measured depth of all deep well events in the well after re-entry and the total measured depth of all deep well events in the well before re-entry.

Example

The Incremental Drilled Distance for a deep re-entered well in the East area is 1,000 metres.

Royalty Credit = [90,000 + (1000 - 300) x 300] = $300,000

4. Deep Discovery Well Royalty Program

The Deep Discovery Program provides the lesser of a three year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells. Deep discovery wells are deeper than 4,000 metres and their surface locations are at least 20 kilometres away from the surface location of any well in a recognized pool of the same formation.

5. Marginal Royalty Program

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) The well event is in a well that has a spud date after May 31, 1998.

(d) The 12 calendar month period referred to in paragraph (b) ends after June 30, 2004.

ROYALTY CALCULATION:

The royalty rate for marginal wells is determined by the Base 9 formula. 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.

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

6. Ultramarginal Royalty Program

A well event is an ultramarginal well event in any producing month if:

(a) The well event produces only Non-Conservation gas.

(b) The well has a well depth of less than 2,500 metres for vertical wells and less than 2,300 metres for horizontal wells.

(c) 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 17 m^3 for every metre of well depth if the well event is in an exploratory wildcat well and 11 m^3 if the well event is in an exploratory outpost well or a development well.

(d) The 12 calendar month period referred to in paragraph (c) ends after January 31, 2007.

(e) The well event is in a well with a spud date after December 31, 2005 or in a reactivated well with a spud date after May 31, 1998 and re-entry date after December 31, 2005.

ROYALTY CALCULATION:

The royalty rate for marginal wells is based on the Base 9 formula. Each marginal well also gets a low productivity reduction factor against the royalty percentage in accordance with the following formula:

$P \times [(60{,}000 - S) / 60{,}000]^{1.5}$

Where:

P is equal to the volume of natural gas produced in the producing month from the ultramarginal 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 ultramarginal wells.

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

7. Summer Royalty Program

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

The Summer Drilling Incentive provides a royalty credit equal to 10% of goods and services costs attributable to individual wells. The credit is 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, or, in any subsequent year, after March 31 and before December 1 of that year.

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.The marginal rate applied to production above 95 m^3/month 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. The marginal rate applied to production above 159 m^3/month is 30%.

Third Tier Oil

The third tier oil royalty rate is the product of the Price Factor (P) and the production sensitive formula. A 1.0 Price Factor applies for wellhead prices up to $125/$m^3$. For prices above this threshold, the Price Factor progressively increases to a maximum of 2.0 at a wellhead price of $175/$m^3$.

At a $300/$m^3$ reference wellhead price (2.0 Price Factor), the third tier royalty formula retains between 0 and 12% of production for well production rates between 0 and 159 m^3/month. The marginal rate applied to production above 159 m^3/month is 24% (the marginal rate is P x B, where B = 12%).

Heavy Oil

The heavy oil royalty formula is the product of the Price Factor (P) and the production sensitive formula. A 1.0 Price Factor applies for heavy oil wellhead prices up to $110/$m^3$. For prices above this threshold, the Price Factor progressively increases.

Heavy oil wells producing at rates less than 20 m^3 per month are not subject to a royalty. At a $250/$m^3$ reference wellhead price (2.4 Price Factor) the heavy oil royalty formula retains between 0 and 16.2% of production for well production rates between 20 m^3/month and 200 m^3/month. The marginal rate applied to production above 200 m^3/month is 26.4% (the marginal rate is P x B, where B = 11%).

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 royalty 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) x 100 when $Q \leq C$

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

Old Oil (pre-November 1975)

K = 792

A = 11.4

B = Marginal rate on production above production threshold = 40%

C = Production threshold = 95 m^3/month

New Oil (post-October 1975)

K = 1058

A = 23.9

B = Marginal rate on production above production threshold = 30%

C = Production threshold = 159 m^3/month

Third Tier Oil (post-December 1999)

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

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

K = 2645

A = 9.56

B = 12%

C = Production threshold = 159 m^3/month

P = Price Factor which is the lesser of:

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

(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 Third Tier Oil Threshold Price.

Heavy Oil (not date sensitive)

R% = 0 when $Q \leq 20$

R% = $P \times [(Q - 20)^2 / (A \times Q)] \times 100$ when $20 < Q \leq 200$

R% = $P \times [(B \times (Q - 200) + K) / Q] \times 100$ when $Q > 200$

K = 13.5

A = 24

B = 11%

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

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

P = Price Factor which is equal to:

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

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 Heavy Oil Threshold Price.

ii. OIL ROYALTY PROGRAMS

1. 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

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 5,000 m^3 per day for conventional gas wells, to 17,000 m^3 per day for coalbed methane wells.

Royalty Credit: A $50,000 royalty credit and $30,000 production tax credit for coalbed methane wells drilled and completed on Crown and Freehold land, respectively. 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 Production Tax

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

Conservation Gas

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

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

Non-Conservation Gas

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

Rate = $[(460 + 15 \times (P – 50)) / P]$ when $P > \$50/10^3m^3$

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

Natural Gas Liquids Tax Rate = 12.25%

Sulphur Tax Rate = 10.25%

B. Crude Oil Freehold Production Tax

The tax rate for oil is expressed as a function of P, the monthly well/tract production:

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

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

3. Corporate Income Taxes

Basic Corporate Tax

The current general corporate income tax rate is 12%. The rate applicable to the first $400,000 of active business income (less the royalty tax rebate) of a Canadian controlled private corporation is 4.5%. 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. The royalty tax rebate will be eliminated commencing the 2007 tax year when the provincial and federal taxation of the resource sector will be harmonized.

III. ALBERTA

1. Royalties

A. Natural Gas

Objective

To retain a fair share of the production as royalty for Albertans the resource owners. The natural gas royalty share is sensitive to the market price and the vintage classification of reserves, with adjustments for low productivity wells.

Natural Gas Royalty Rate

- Crown gas royalty quantities are calculated by applying the natural gas royalty rate to the energy content of the natural gas stream on a monthly basis (expressed in gigajoules).
- The natural gas royalty rate is the Facility Average Royalty Rate (FARR) set monthly for each gas plant (the exception is low productivity gas, which is subject to a reduced royalty rate described below). The FARR is the weighted average of the royalty rates for the components in the gas stream at the applicable plant. These in stream components (ISC's) include Methane (C1), Ethane (C2), Propane (C3), Butanes (C4), and Pentanes-Plus (C5+).
- Low productivity well events (reporting an average gas production rate below 16.9 10^3m^3/day in a production month) are subject to the low productivity well allowance. This allowance reduces the natural gas royalty rate as gas production declines to a minimum of 5%. The same allowance applies to a low productivity well event in a crude oil well, if the well's average monthly oil production is below 0.15 m^3/day.

Royalty Rates for ISCs and Natural Gas Liquids

- The same monthly royalty rate applies for natural gas liquid components (C2, C3, C4 and C5) as an ISC or an extracted liquid. The only exception is low productivity liquid ethane, which benefits from the low productivity well allowance. The liquid ethane rate progressively falls as gas production declines from the 16.9 10^3m^3/day threshold, to a minimum of 5%. The same allowance applies to a low productivity well event in a crude oil well, if the well's average monthly oil production is below 0.15 m^3/day.
- The royalty rates for methane, ethane and pentanes-plus are vintage sensitive.
- Price sensitivity is based on the component-specific par price and select price. With the exception of pentanes-plus, the par price is set monthly and is equal to the current month's ISC reference price. The pentanes-plus par price is equal to the current month's pentanes-plus liquid reference price minus a transportation allowance. The select price is adjusted annually for inflation. The minimum royalty rate applies when the par price is less than the select price. For par prices above the select price, the royalty rate is price sensitive until the maximum royalty rate is reached.
- The following table depicts the minimum and maximum royalty rates for each component with the exception of low productivity liquid ethane, which is subject to a 5% minimum royalty rate.

	Methane: ISC		Natural Gas Liquid Components: ISC / Extracted Liquid					
	Old C1	New C1	Old C2	New C2	C3	C4	Old C5	New C5
Min. Rate	15%	15%	15%	15%	15%	15%	22%	22%
Max. Rate	35%	30%	35%	30%	30%	30%	50%	35%

Valuation for Natural Gas and ISCs

- A reference price is set monthly for each ISC. The reference price is the weighted average price for volumes consumed in Alberta and volumes exported from Alberta in the month, reduced by the average cost to transport the ISC to market. The ISC reference prices reflect the implied amounts paid for the ISCs as reported for natural gas sales. The transport cost differs for each ISC.
- With the following exception, Crown gas royalty quantities are valued at a plant-specific Facility Average Price (FAP) set each month. The FAP is the weighted average of the reference prices for the ISC quantities in the plant's Crown gas production.
- Qualifying producers can value the Crown gas 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.

Valuation for Natural Gas Liquids

- For Crown royalty purposes, liquid ethane is valued as ISC ethane.
- Reference prices for liquid propane, butanes and pentanes-plus are weighted average sales prices for these liquids in the Edmonton area. Reference prices for liquid propane, butanes and pentanes-plus are reduced by regional transportation allowances and a fractionation allowance if produced liquids are in a mix.

i. GAS ROYALTY FORMULAS AND RATES

Distinction is made between old gas and new gas, and between natural gas components – 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 inputs and formulas used to determine the royalty rate for each product are:

Natural Gas

A plant-specific Facility Average Royalty Rate applies to well events reporting average daily gas production above 16.9 10^3m^3/day in a production month. Well events producing below this rate are subject to the low productivity well allowance.

R% = Facility Average Royalty Rate.
= Weighted average of royalty rates for ISC's in the gas stream at the applicable gas plant.

Methane, Ethane, Propane, and Butane

R% = Royalty Rate for each of C1, C2, C3, and C4
= BR when PP $\leq$ 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). PP = current month's ISC reference price.
J = Joule (a unit which expresses quantity of energy).
G = Giga (prefix for 10^9).

Well events reporting average daily gas production below 16.9 10^3m^3/day in a production month qualify for the low productivity allowance on liquid ethane.

Pentanes-Plus

R% = Royalty Rate for C5+
= BR when PP $\leq$ 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). PP = current month's pentanes-plus liquid reference price minus a transportation allowance.

2006 Select Prices:

Old Methane $/GJ	New Methane $/GJ	Old Ethane $/GJ	New Ethane $/GJ	Propane $/GJ	Butanes $/GJ	Pentanes-Plus $/m^3
0.418	1.419	0.418	1.419	1.419	1.419	50.73

Low Productivity Well Allowance

Natural Gas

The natural gas royalty rate for a well event that qualifies for the low productivity well allowance is calculated as:

R% = Rc% - (Rm% - 5) x [((16.9 - ADP) / 16.9)^2] when ADP < 16.9

Where:
Rc% = The old or new methane royalty rate (whichever is applicable) for the production month.
Rm% = The old or new methane royalty rate (whichever is applicable) for the production month.
ADP = Average daily gas production (10^3m^3/day/well) over a month.

Liquid Ethane

The liquid ethane royalty rate for a well event that qualifies for the low productivity well allowance is determined as per the natural gas low productivity allowance with Re% replacing Rc%. Re% is the applicable old or new ethane royalty rate for the production month.

Sulphur royalty rate

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** 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** to all royalty clients that own gathering, compressing and processing facilities;
- **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 ROYALTY PROGRAMS

1. Royalty Adjustment Program For Deep Marginal Gas Wells

Refer to Alberta Energy Information Letter 2006-26.

On August 22, 2006, the Alberta Government announced the termination of the existing royalty holiday program for deep natural gas wells. A new royalty adjustment program for deep marginal gas wells has been established for wells drilled on Crown leases or licenses with a term commencement date of September 1, 2006 or later. The program is designed to facilitate the development of lower grade natural gas resources located below 2,500 metres. The royalty adjustment is available to new or deepened gas wells that produce below the Qualifying Production Rate (QPR) and is sensitive to the vertical and non-vertical depth of the well.

Benefits

The royalty adjustment reduces the gross royalty rate on gas and products recovered from a qualified well to a minimum of 5%. The royalty adjustment commences with production, and continues until the cumulative net royalty adjustment equals the royalty adjustment value. The royalty adjustment value is limited to a maximum of $3,600,000 in net royalty per well regardless of the number of producing zones. Eligibility lasts for a maximum period of ten years following the finished drilling date applicable to the drilling or deepening of the well.

The royalty adjustment value is the sum of the vertical and the non-vertical benefits, which increase with well depth (and hence the incremental drilling cost below 2,500 metres). The vertical and non-vertical benefits are calculated as follows:

- The vertical benefit will be an amount determined from the table below based on the vertical depth of the well.
- The total measured depth less the vertical depth of the well is the non-vertical depth. The non-vertical depth is multiplied by $1,000 to determine the non-vertical benefit.

Eligibility

To qualify for the royalty adjustment, a well must:

- Commence spudding or deepening in the September 1, 2006 - August 31, 2011 period.
- Be drilled on a Crown lease or license agreement with a term commencement date on or after September 1, 2006 (for Crown lands acquired prior to September 1, 2006, an election, in writing to the Department, can be made to qualify the well for this royalty adjustment instead of the Deep Gas Royalty Holiday Program).
- Be drilled into a producing zone, the top of which is greater than 2,500 metres vertical depth.
- Be drilled in a drilling spacing unit which is wholly outside a deep gas pool designated by the Alberta Energy and Utilities Board (AEUB) as at June 1, 1985.

- Have an average daily production (ADP) not exceeding the QPR in each 12 month reporting period.
- The ADP is determined by dividing the total quantity of raw natural gas and field condensate from all zones produced from the well during the period by the number of days in the period. For the first 12 month period the QPR is based on the following formula:

1. For wells with a total measured depth < 3500 m:

$$QPR = \left[1.1327\ e^3\ m^3 + \left\{.0850\ e^3\ m^3 \times \frac{(MD - 2500m)}{100\ m}\right\}\right] \times \left[\frac{MD}{100\ m}\right]$$

2. For wells with a total measured depth > 3500 m:

$$QPR = \left[1.9822\ e^3\ m^3 + \left\{.1133\ e^3\ m^3 \times \frac{(MD - 3500m)}{100\ m}\right\}\right] \times \left[\frac{MD}{100\ m}\right]$$

Where:
MD is the total measured depth of the well on the last day of the applicable period. The QPR is 80% of the first period QPR for the second twelve month period and 68% of the first period QPR for the third and all subsequent twelve month periods.

- If the natural gas recovered from a qualifying well has an acid gas content of more than 15% by volume, the QPR is adjusted as follows:

Adjusted QPR = QPR / [100% - (H_2S% + CO_2% - 15%)]

Where H_2S% and CO_2% are the percentage of hydrogen sulphide and carbon dioxide contained in the raw gas stream by volume, respectively.

- Oil wells and oil sands wells are excluded from receiving the adjustment.

2. Deep Gas Royalty Holiday Program (DGRHP)

Refer to Alberta Energy Information Letter 85-29.

Eligibility under the Deep Gas Royalty Holiday program (DGRHP) is closed for wells drilled on Crown leases or licenses with a term commencement date on or after September 1, 2006. Wells drilled on Crown leases or licenses with a term commencement date prior to September 1, 2006 remain eligible for a limited time frame (spudding or commencement of drilling must occur before April 1, 2010).

Benefits

The royalty holiday commences with production, and continues until the cumulative net royalty exempted equals the holiday value. The holiday value will be an amount determined from the table below based on the vertical depth of the well. The holiday value is limited to a maximum of $3,600,000 in net royalty per well. Eligibility will last for a maximum period of ten years following the finished drilling date applicable to the drilling or deepening of the well.

Eligibility

To qualify for the holiday, a well must:

- Be drilled or deepened on an agreement having a term commencement date earlier than September 1, 2006.
- Commence spudding or deepening before April 1, 2010.
- Be drilled into a producing zone, the top of which is greater than 2,500 metres vertical depth.
- Be drilled in a drilling spacing unit which is wholly outside a deep gas pool designated by the AEUB as at June 1, 1985.
- Oil wells and oil sands wells are excluded from receiving DGRHP benefits.

Value of Royalty Benefit:

Deep Marginal Wells (Vertical Benefit Only) and DGHRP Wells

Vertical 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	–

3. 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 AEUB. The AEUB 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 1.00.

Eligibility

Conventional oil wells may qualify for OFSG benefits as follows:

1) 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 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.

2) 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 AEUB Upstream Petroleum Industry Flaring Guide G-60. The Department will forward the application to the AEUB for assessment of the economic information.

Non Qualifying Wells

Natural gas wells and bitumen wells are not eligible.

4. Sulphur Emission Control Assistance Program (SECAP)

Refer to Alberta Energy Information Letter 99-19.

Benefits

SECAP provides royalty credits equal to 50 per cent of the costs of eligible equipment, including facilities that recover sulphur from acid gas or dispose of acid gas into an underground formation.

Eligibility

SECAP eligibility is closed for costs incurred after April 30, 2006. The deadlines to submit outstanding capital and operating costs claims are March 31, 2007 and June 30, 2007, respectively.

5. 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 the Alberta Enhanced Oil Recovery Section for a full description of eligibility criteria and benefits.

6. Innovative Energy Technologies Program

Refer to Alberta Energy Information Letter 2004-33.

This program represents a $200 million commitment over five years by Alberta Energy to provide royalty adjustments to pilot and demonstration projects that use innovative technologies to increase recoveries from oil, natural gas and in-situ oil sands reserves. The program is also designed to assist industry to find commercial technical solutions to the gas over bitumen issue that will allow efficient and orderly production of both resources. Alberta Energy believes that a producer's ability to undertake certain projects is often limited by the related technical and financial risk. Royalty reductions provided by this program will assist in reducing financial risk, thereby encouraging producers to undertake the projects.

Benefits

Projects approved under this program will be able to receive royalty adjustments of up to 30% of eligible project costs. The royalty adjustment for any one project will be limited to a maximum of $10 million. The actual level of funding for each approved project will be determined by Alberta Energy based on the merits of that project proposal and the availability of funds. Royalty adjustments can be applied against oil, natural gas or oil sands royalty obligations.

Eligibility

Projects must show potential to:

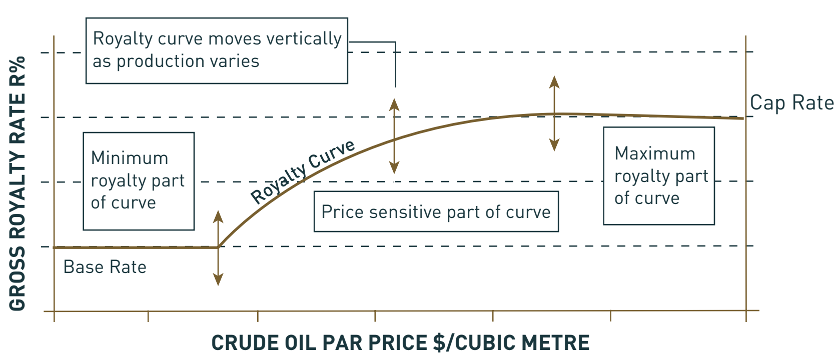
- Improve the economics of conventional oil, in situ oil sands and natural gas development.
- Expand the prospects for sustainable resource development.
- Result in incremental royalties to the Province of Alberta.
- Further the development, application and commercialization of technologies, processes and systems to meet the need for cleaner energy sources.

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 the oil pool vintage 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 1: 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 = $31.54/m^3$ for both non-heavy and heavy oil for 2006

New Oil (post-March 1974)

B = $100.47/m^3$ for non-heavy oil for 2006

B = $67.77/m^3$ for heavy oil for 2006

Third Tier Oil (post-September 1992)

B = $144.22/m^3$ for both non-heavy and heavy oil for 2006

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 $A \geq (6 \times B)$

New Oil: R% = BR x 3.0 x 100 when $A \geq (3 \times B)$

Third Tier Oil: R% = BR x 2.5 x 100 when $A \geq (2 \times B)$

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) x .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 $20 \leq Q < 190.7\ m^3$/month

S = 13.2 + [(Q - 190.7) x .115385] when $Q \geq 190.7\ m^3$/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 are remitted to the Crown.

ii. OIL ROYALTY PROGRAMS

1. Third Tier Exploration Well Royalty Exemption

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 Re-entry Oil Royalty Reduction

Refer to Alberta Energy Information Letters 93-4 and 2006-24.

No new wells will be approved for the program effective November 1, 2006. The program will be terminated effective September 1, 2012. No royalty reductions will be issued after that date.

Benefits

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

Effective September 1, 2007, the cumulative royalty reduction under the program will be capped at $900,000 per well.

3. Enhanced Recovery Of Oil Royalty Reduction

Refer to Alberta Energy Information Letter 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
- Injectant
- Transportation
- Consumed Energy
- Breakthrough Processing Allowance
- 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:

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

The reduction in oil royalties is the lesser of:

- (Scheme allowed costs) x (crown interest) x (royalty rate) or
- (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. CO_2 Projects Royalty Credit

Refer to Alberta Energy Information Letter 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 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.

5. Experimental Project Petroleum Royalty

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.

6. Reactivated Well Royalty Exemption

Refer to Alberta Energy Information Letters 93-3 and 2006-22.

Benefits

In the current program, a royalty exemption applies to the first 8,000 m^3 of production after a well is reactivated. The 8,000 m^3 production volume cap is converted to a $150,000 royalty value cap effective September 1, 2007. 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. 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.

7. Low Productivity Well Royalty Reduction

Refer to Alberta Energy Information Letters 93-2 and 2006-23.

Alberta Energy announced changes to this program effective September 1, 2007. The program will be broadened to encourage investment in extremely low producing oil wells (less than 10 barrels per day). The 16,000 m^3 production volume cap will be converted to a $50,000 royalty value cap.

Current program benefits in effect until August 31, 2007

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.

New program benefits effective September 1, 2007

The royalty rate will be calculated based on the lower of actual production (P) or threshold quantity for each well shown below. The production range for existing wells will be determined based on average monthly production during the most recent 6 months that the well produced. The royalty reduction applies until the cumulative royalty reduction equals the $50,000 royalty value cap.

Production Range	Threshold Quantity
$P < 24\ m^3$ per month	24 m^3
$24\ m^3 < P < 47\ m^3$ per month	47 m^3
$47\ m^3 < P < 73\ m^3$ per month	73 m^3

Qualifying Types of Wells

- Oil well or oil sands well.
- 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.
- 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.
- The well did not produce more than 121 m^3/month of oil or oil sands in any month during the qualifying period.
- 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.

An application is not required to qualify for the program.

8. Innovative Energy Technologies Program

Refer to Alberta Energy Information Letter 2004-33.

Natural gas, crude oil, and oil sands pilot and demonstration projects approved under this program are eligible to receive royalty adjustments. Refer to "Gas Royalty Programs" for a description of program benefits and eligibility criteria.

C. Gas from Coal

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

D. Oil Sands

i. OIL SANDS ROYALTY REGIME

Background

In 1993, the joint industry–government National Task Force on Oil Sands Strategies was launched to assess the technical, socio-economic, environmental and marketing aspects of oil sands development and recommend strategies to address these issues.

In its 1995 report, the task force outlined a comprehensive, new royalty approach for Alberta's oil sands industry. A key recommendation was that royalty should be established through legislation rather than individual Crown agreements. That is, the royalty regime should be generic: the same rules should apply in the same situations and the same clear, standardized royalty terms should apply to all new oil sands projects. The task force believed that a generic approach to oil sands royalty would place all new projects on a level playing field. Standard royalty terms would create fiscal certainty and stability, and encourage oil sands investment. The Government of Alberta accepted that recommendation of the task force and began work to develop legislation and policy to support a generic oil sands royalty regime.

Alberta's current generic oil sands royalty regime dates to July 1, 1997, when the

Oil Sands Royalty Regulation, 1997 (AR 185/97) came into force.

Objectives

Alberta's generic oil sands royalty regime provides a stable, competitive fiscal framework that supports the major investments needed to develop the province's oil sands resources. The regime is designed to:

- Encourage the development of the oil sands while ensuring a fair return to Albertans, who own the province's resources.
- Create a stable fiscal and regulatory framework that facilitates oil sands development by private sector companies based on the expectation of a reasonable rate of return. The Government of Alberta does not provide grants, loans, loan guarantees, or any other "special deals" to encourage oil sands investment.
- Ensure that investment in the oil sands provides developers a rate of return that is competitive with other petroleum development opportunities around the world.

Legislation

The *Mines and Minerals Act*, RSA 2000, c. M-17 was amended in May 1997 to embed the generic oil sands royalty formulas and core rates in legislation.

The Oil Sands Royalty Regulation, 1997 (AR 185/97) came into force on July 1, 1997. It sets out the main administrative provisions of the royalty regime, including:

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

Key Features of the Oil Sands Royalty Regulation, 1997

Project Based:

Oil sands royalty is assessed on a project basis. Once a project proponent has their production schemes, operations, processing plants, wells and facilities approved by the Alberta Energy and Utilities Board, they can apply to the Department for project status under the Oil Sands Royalty Regulation, 1997. Approval as an oil sands project is by Ministerial Order.

The Minister must, before issuing an oil sands project approval order (or amendment), consider, without limitation:

- Whether all project-related assets and operations are under **common management.**
- Whether all project components comply with the **location requirements** specified in the Regulation.
- Whether the project and all its components are **economically justifiable** and function as an integrated **economic unit.**
- The project's **impact to the royalty** payable to the Crown.

In issuing a project approval order, the Minister may take additional considerations into account, as warranted by the specifics of the situation.

Oil sands recovery schemes that do not apply for project status under the generic regime, or are not approved as projects, pay royalty at conventional oil rates.

Royalty:

The Regulation establishes a "revenue minus cost" royalty regime. Before a project reaches payout (i.e. the point when the developer has recovered all the allowed costs of the project, including a return allowance on those costs set at the Government of Canada long-term bond rate ["LTBR"]), the applicable royalty is 1% of the gross revenue of the oil sands project. Costs incurred up to three years prior to the effective date of the project (as specified by the project's approval) are included as part of recoverable costs for the project owner: some costs incurred more than three years prior to the project's effective date may also be allowable.

The gross revenue of an oil sands project is the sum of all the quantities of oil sands products produced from the development area multiplied by their respective unit prices (less the cost of any diluent included in product sales). The unit price, calculated at the royalty calculation point (generally the point at which the product leaves the project lands), is:

Unit Price = (TC – HC) / TD

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

HC = all handling charges, such as pipeline tariffs, 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 disposed of.

Revenue generated from sources other than the sales of oil sands products is called "other net proceeds" and is deducted from allowed costs rather than being treated as project revenue.

After a project reaches payout, the royalty payable to the Crown is equal to the greater of:

a) 1% of gross revenue for the period.

b) 25% of net revenue for the period.

For royalty purposes, net revenue equals project revenue less allowed costs.

Allowed Costs:

To be an allowed cost of a project, a 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 for one of the purposes set out in the Regulation: to recover, purchase, process, transport, or market oil sands products, provide services in support of these activities, or conduct research on oil sands recovery.

All allowed costs (operating and capital) of the project are 100% credited to the project in the year in which they are incurred. If, after a project reaches payout, it incurs a negative net revenue in any year (as a result of an operating loss, or capital expenditures) that negative net revenue is carried forward, with a return allowance, as an allowed cost in the subsequent year. The project will continue to pay royalty of 1% of gross revenues until it again records a positive net revenue for a period.

Reporting and Payment Mechanisms:

The Regulation prescribes the royalty payment and reporting requirements of approved projects. Royalty is paid monthly at the applicable (pre- or post-payout) rate.

The form of reporting differs between pre- and post-payout projects. However, both types of projects are required to submit monthly and annual reports, as well as forecast reports estimating future royalties. Reporting details can be found in the Alberta Oil Sands Royalty Guidelines.

ii. OIL SANDS ROYALTY PROGRAMS

Innovative Energy Technologies Program

Refer to Alberta Energy Information Letter 2004-33.

Natural gas, crude oil, and oil sands pilot and demonstration projects approved under this program are eligible to receive royalty adjustments. Refer to "Gas Royalty Programs" for a description of program benefits and eligibility criteria.

2. Freehold Taxes

A. Natural Gas Freehold Mineral Rights 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 (GWCF) calculated for each well on the basis of production. The calculation provides for a tax rate reduction on low productivity wells. In addition, there is an annual tax exemption of $1,600 for gas and/or oil tax allowed for each title owner.

FMT = FGF + GWCF

Natural Gas

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

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) x (16.9 - ADP)^2] / (16.9)^2}

Condensate

GWCF = 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 = $(Q / 4) - 228.84$ 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

B. Crude Oil Freehold Mineral Rights 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. The calculation provides for a tax reductions for low productivity wells. In addition, there is an annual tax exemption of $1,600 for gas and/or oil tax allowed for each title owner.

FMT = COF + SGF

Crude Oil

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

Solution Gas

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 10.0% of the amount taxable in Alberta Where:

Alberta Taxable Income = (Canadian Taxable Income – Royalty Tax Deduction) x (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 = $\dfrac{\text{Taxable income in Alberta}}{\text{Taxable income in Canada}}$

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 3.0% for firms that qualify as small businesses.

Alberta Royalty Tax Credit

This program was terminated effective January 1, 2007.

IV SASKATCHEWAN

1. Royalties

A. Natural Gas

Refer to Information Circulars at the following website for further information on the Natural Gas Royalty Regime:

http://www.ir.gov.sk.ca/default.aspx?DN=3758,3620,3384,2936,Documents

Overview

- Crown royalty rates are sensitive to the individual productivity of each well. In addition, royalty rates are adjusted each month based on the level of the Provincial Average Gas Price (PGP) which is established by the Province each month. The PGP represents the weighted average fieldgate price, expressed in $\$/10^3m^3$, received by producers during the month for the sale of all Saskatchewan gas that is subject to royalty.
- The Crown royalty share of the production volume is calculated on a well by well basis by applying the applicable royalty rate to the volume of gas produced from each well on a monthly basis.
- Each operator must elect to use either the PGP or the Operator Average Gas Price (OGP) for purposes of valuing the Crown's royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price ($\$/10^3m^3$) received by the operator for sales of Saskatchewan gas during the month. Operators that elect to use the OGP, may at some point change their election to use the PGP. However, operators that elect the PGP, may not change their election.
- The value of the Crown royalty share is determined by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month. The wellhead value is determined by subtracting the Gas Cost Allowance from the OGP or PGP, as elected.

Royalty Exemption for Natural Gas Produced from Oil Wells

- Natural gas produced from oil wells is not subject to royalty unless:
  - the well is drilled on or after October 1, 2002 and the gas is gathered for use or sale;
  - the well is drilled before October 1, 2002, produces at a gas-oil-ratio greater than 3,500 cubic metres of gas per cubic metre of oil, and the gas is gathered for use or sale; or
  - the well is drilled before October 1, 2002 and received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil-ratio penalty.

Natural Gas Liquids

- Saskatchewan does not levy a royalty on natural gas liquids or by-products recovered at a gas processing plant.
- By-products contained in natural gas that is sold at a gas plant inlet in a raw (unprocessed) state are subject to the natural gas royalty, provided the gas is subject to royalty.
- Gas liquids that are produced and measured at the wellhead are treated as crude oil for royalty purposes.

Royalty Categories and Description of Royalty Principles

Refer to Information Circular PR-IC02.

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

- For **Old Gas** (gas produced from gas wells drilled prior to October 1, 1976), the 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.
- For **New Gas** (gas produced from gas wells drilled on or after October 1, 1976), the 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.
- For **Third Tier Gas** (gas produced from gas wells drilled on or after February 9, 1998), the 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.
- For **Fourth Tier Gas** (gas produced from oil or gas wells drilled on or after October 1, 2002 or from oil wells drilled prior to that date where the gas-oil-ratio exceeds 3,500 cubic metres of gas per cubic metre of oil during the month), the 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.
- The fourth tier royalty rate is 0%, if the monthly gas production rate from a gas well is less than 25 10^3m^3/month or if the monthly gas production rate from an oil well is less than 64.7 10^3m^3/month.

i. GAS ROYALTY FORMULAS AND RATES

Old, New and Third Tier Gas

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

R% = (Kg – (Xg / MPG)) - SRC when MGP > 115.4 10^3m^3/month

Fourth Tier Gas from Gas Wells

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

R% = (Cg x MGP) - Dg when 25 < MGP $\leq$ 115.4 10^3m^3/month

R% = (Kg – (Xg / MPG)) when MGP > 115.4 10^3m^3/month

Fourth Tier Gas from Oil Wells

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

R% = (Kg – (Xg / MGP)) when MGP > 64.7 10^3m^3/month

Where:

R% = Crown royalty rate to a minimum of 0%.

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

SRC = Saskatchewan Resource Credit of 2.5% for third tier gas and 1% for old gas and new gas. Note: the SRC does not apply to fourth tier gas.

Kg, Xg, Cg and Dg are constants derived from the following formulas:

Old Gas

Kg = 26 + (32.5 x (PGP - 35) / PGP)

Xg = Kg x 57.69

Cg = Kg / 230.76

New Gas

Kg = 19.5 + (26 x (PGP - 35) / PGP)

Xg = Kg x 57.69

Cg = Kg / 230.76

Third Tier Gas

Kg = 19.5 + (26 x (PGP - 50) / PGP)

Xg = Kg x 57.69

Cg = Kg / 230.76

Fourth Tier Gas from Gas Wells

Kg = 6.75 + (33.73 x (PGP - 50) / PGP)

Xg = Kg x 64.7

Cg = Kg / 205.76

Dg = Kg / 8.23

Fourth Tier Gas from Oil Wells

Kg = 6.75 + (33.73 x (PGP - 50) / PGP)

Xg = Kg x 64.7

Where: PGP is the Provincial average fieldgate price ($/$10^3m^3$) set for each month, 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.

ii. COST ALLOWANCES

Saskatchewan producers receive a fixed gas cost allowance of $10 per thousand cubic metres for all gas types. This allowance is in recognition of costs incurred in gathering and compressing the natural gas. Since there is no royalty on gas liquids recovered at a gas plant, higher costs associated with processing gas are not recognized in the allowance.

iii. GAS ROYALTY PROGRAMS

Refer to Information Circular PR-IC04.

Exploratory Drilling Incentive

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

To qualify, a gas well must be located more than 4.8 kilometres from the nearest gas well or be producing from a geological system below which all other gas wells located within 4.8 kilometres are cased through or into.

B. Oil

Overview of Conventional Oil Royalty

- Crown royalty rates are sensitive to the individual productivity of each well as well as the type of oil produced from the well. Royalty rates are also adjusted each month based on the level of the reference price set by the Province for each of the oil types.

- Separate reference prices are established each month for heavy oil (HOP), non-heavy oil (NOP) and oil produced in the southwest area of the province (SOP). The HOP, SOP and NOP prices represent the average wellhead price, expressed in $/m^3, received by producers during the month for sales of that oil type in the province.
- The Crown royalty share of the production volume is calculated on a well by well basis by applying the applicable royalty rate to the volume of oil produced from each well on a monthly basis.
- The value of the Crown royalty share is determined by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month. The wellhead value is determined by subtracting eligible transportation expenses from the actual price received by the producer for the sale of the oil at the point of sale.

Oil Types and Conventional Royalty Categories

Refer to Information Circular PR-IC01.

- For royalty purposes, oil production is divided into three types of oil:
  - **Heavy Oil** – 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** - Oil produced from wells drilled on or after February 9, 1998 and incremental oil produced from waterfloods commencing operation on or after February 9, 1998 in the southwest area of the province. The southwest area includes the area within Townships 1 through 21 in Ranges 1 through 30, west of the third meridian.
  - **Non-Heavy Oil** – all oil other than Heavy oil and Southwest-designated oil.
- Further distinction is made within each oil type between old oil, new oil, third tier oil and fourth tier oil royalty classifications. However, all heavy oil and oil produced in the southwest area of the province that would otherwise be considered old oil, has been reclassified to new oil. The following is brief description of each royalty classification:
  - **Old Oil** - non-heavy oil from wells drilled prior to 1974.
  - **New Oil** - oil from wells drilled on or after January 1, 1974.
  - **Third Tier Oil** - oil from wells drilled on or after February 9, 1998 and incremental oil from new or expanded waterflood projects that commence operation on or after that same date.
  - **Fourth Tier Oil** – oil from wells drilled on or after October 1, 2002 and incremental oil from new or expanded waterflood projects that commence operation on or after that same date.

Royalty Principles

- Different revenue sharing principles apply to each oil type and royalty classification.
- The royalty formulas are all derived from the basic principle of retaining a base royalty rate on a base price plus a marginal royalty rate on the remaining price above the base price. This principle is applied at a fixed reference well production rate.

The following table includes the base royalty rate, base price, marginal royalty rate and reference well production rate applicable to each of the oil types and royalty classifications:

	Base Royalty Rate	Base Price	Marginal Royalty Rate	Reference Well
Heavy Oil				
New Oil	10%	$50/m^3	25%	100 m^3/month
Third Tier	10%	$100/m^3	25%	100 m^3/month
Fourth Tier	5%	$100/m^3	30%	250 m^3/month
Southwest Designated				
New Oil	12.5%	$50/m^3	35%	100 m^3/month
Third Tier Oil	12.5%	$100/m^3	35%	100 m^3/month
Fourth Tier Oil	5%	$100/m^3	30%	250 m^3/month
Non-Heavy Oil				
Old Oil	20%	$50/m^3	45%	100 m^3/month
New Oil	15%	$50/m^3	35%	100 m^3/month
Third Tier Oil	15%	$100/m^3	35%	100 m^3/month
Fourth Tier Oil	5%	$100/m^3	30%	250 m^3/month

A) OIL ROYALTY FORMULAS AND RATES

Old, New and Third Tier Oil

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

Fourth Tier Oil

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

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

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

Where:

R% = Crown royalty rate to a minimum of 0%.

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

SRC = Saskatchewan Resource Credit of 2.5% applicable to oil produced from vertical oil and gas wells drilled on or after April 1, 1998 and before October 1, 2002, and to incremental oil produced from new or expanded enhanced oil recovery or waterflood projects that commenced operation between those same dates. The SCR rate is 1% for all other old, new or third tier oil. The SRC does not apply to fourth tier oil.

K, X, C and D are constants derived by the following formulas:

	K	X	C	D
Heavy				
New	13 + 19.5 x (HOP - 50) / HOP	K x 23.08	-	-
3rd Tier	13 + 19.5 x (HOP - 100) / HOP	K x 23.08	-	-
4th Tier	7.14 + 35.71 x (HOP - 100) / HOP	K x 75	K/247.48	K/9.9
Southwest Designated				
New	16.25 + 29.25 x (SOP - 50) / SOP	K x 23.08	-	-
3rd Tier	16.25 + 29.25 x (SOP - 100) / SOP	K x 23.08	-	-
4th Tier	7.14 + 35.71 x (SOP - 100) / SOP	K x 75	K/247.48	K/9.9
Non-heavy				
Old	26 + 32.5 x (NOP - 50) / NOP	K x 23.08	-	-
New	19.5 + 26 x (NOP - 50) / NOP	K x 23.08	-	-
3rd Tier	19.5 + 26 x (NOP - 100) / NOP	K x 23.08	-	-
4th Tier	7.14 + 35.71 x (NOP - 100) / NOP	K x 75	K/247.48	K/9.9

Where: **HOP** is the average heavy oil wellhead price ($/$m^3$) set for each month, to a minimum of $50/$m^3$ for new oil and $100/$m^3$ for third tier and fourth tier oil.

SOP is the average southwest designated oil wellhead price ($/$m^3$) set for each month, to a minimum of $50/$m^3$ for new oil and $100/$m^3$ for third tier and fourth tier oil.

NOP is the average non-heavy oil wellhead price ($/$m^3$) set for each month, to a minimum of $50/$m^3$ for old and new oil, and $100/$m^3$ for third tier and fourth tier oil.

Transportation Allowances

Refer to Information Circular PR-IC09.

In determining the well-head value of oil for royalty purposes, Saskatchewan producers are allowed to deduct arm's length transportation expenses incurred in transporting clean oil from the well-head to the point at which the oil is sold.

ii. OIL ROYALTY PROGRAMS

1. Vertical Well Drilling Incentives

Refer to Information Circular PR-IC03.

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.

Non-Deep = Any well other than a deep well.

Exploratory = Drilled more than 3 kilometres from the nearest oil well or producing from a geological system below which all other oil wells located within 3 kilometres are cased through or into.

Development= Any well other than an exploratory well.

2. Horizontal Well Drilling Incentives

Refer to Information Circular PR-IC05.

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 Well	6,000 m^3
Deep Horizontal Oil 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.
Non-Deep	=	Any horizontal well other than a deep horizontal well.

3. Other Oil Royalty Programs

New or Expanded Waterflood Projects

Refer to Information Circular PR-IC06.

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 is 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, qualify under this program.

High Water-Cut Program

Refer to Information Circular PR-IC12.

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 had 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.

Workover Reclassification Program

Refer to Information Circular PR-IC07.

The royalty classification of any well that produces old oil (pre-1974) may be reclassified to new oil for royalty purposes if the operator undertakes an approved major workover to improve oil recovery rates.

4. Enhanced Oil Recovery (EOR) Royalty Regime

Refer to Information Circulars PR-IC11 and PR-IC11A.

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 projects that commenced operation prior to April 1, 2005 and the other for projects or project expansions that commenced operation on or after April 1, 2005. In both cases, the royalty level is sensitive to project profitability and investment payout.

The EOR royalty rate is calculated as follows:

	Projects Commencing Before April 1, 2005	Projects Commencing On or After April 1, 2005
Before Investment Payout	Intermediate of (1% of Gross Revenue, 5% of Gross Revenue or 10% of Net Revenue) - SRC	1% of Gross Revenue
After Investment Payout	Greater of (5% of Gross Revenue or 30% of Net Revenue) - SRC	20% of Net Revenue

Where:

Gross Revenue = The total 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 deemed to be 100%.

Net Revenue = Gross Revenue minus allowable costs.

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. The SRC does not apply to production from new or expanded projects commencing on or after April 1, 2005.

2. Freehold Taxes

Refer to Information Circulars at the following website for further information on the Freehold Tax Regime: www.ir.gov.sk.ca/royaltytaxinfocirc

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

A. Natural Gas Freehold Production Tax

Overview

- The freehold production tax structure is similar in concept to the Crown royalty structure. Like Crown royalty rates, production tax rates are sensitive to the individual productivity of each well and tax levels are also adjusted each month based on the level of the Provincial Average Gas Price (PGP) which is established for each month.
- The amount of tax payable on the production of freehold gas is determined in much the same way as the royalty payable on the production of Crown gas.

i. GAS TAX FORMULAS AND RATES

Refer to Information Circular PR-IC02.

The freehold production 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) from the calculated royalty rate that would have applied had the production come from Crown land.

PTF = 6.9 for old gas
= 10.0 for new gas and third tier gas
= 12.5 for fourth tier gas

ii. COST ALLOWANCES

Saskatchewan producers receive the same fixed gas cost allowance of $10 per thousand cubic metres as allowed within the Crown royalty calculation. This allowance is in recognition of costs incurred in gathering and compressing the natural gas. Since there is no royalty on gas liquids recovered at a gas plant, higher costs associated with processing gas are not recognized in the allowance.

iii. GAS TAX PROGRAMS

Refer to Information Circular PR-IC04

Exploratory Drilling Incentive

Eligibility of freehold gas wells for a volume-based tax reduction is determined in the same manner as the volume-based Crown royalty reduction. The first 25 million m^3 of natural gas produced from a qualified exploratory natural gas well is subject to a freehold production tax rate of 0%.

To qualify, a gas well must be located more than 4.8 kilometres from the nearest gas well or be producing from a geological system below which all other gas wells located within 4.8 kilometres are cased through or into.

B. Oil Freehold Production Tax

Overview

- The freehold production tax structure is similar in concept to the Crown royalty structure. Like Crown royalty rates, production tax rates are sensitive to the individual productivity of each well and tax levels are also adjusted each month based on the level of the reference price set by the Province for each of the oil types.
- The amount of tax payable on the production of freehold oil is determined in much the same way as the royalty payable on the production of Crown oil.

Oil Types and Conventional Freehold production tax Categories

- The oil types and conventional categories for freehold production tax purposes are the same as those described in the oil royalty section.

i. OIL TAX FORMULAS AND RATES

Refer to Information Circular PR-IC01.

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.

Freehold production tax rate % = Crown royalty rate % - PTF

Where:

PTF = 6.9 for old oil
= 10.0 for new oil and third tier oil
= 12.5 for fourth tier oil

Transportation Allowances

Refer to Information Circular PR-IC09.

In determining the wellhead value of oil for freehold production tax purposes, Saskatchewan producers are allowed to deduct arm's length transportation expenses incurred in transporting clean oil from the wellhead to the point at which the oil is sold.

ii. OIL TAX PROGRAMS

All oil programs that are offered for wells and production from Crown land are also available to wells and production from freehold land. Eligibility for drilling incentives, waterflood incentives, oil well reactivation program and high water-cut program are the same as those described for oil in the royalty section.

1. Drilling Incentives

Refer to Information Circulars PR-IC03 and PR-IC05.

The freehold production tax rate is reduced to 0% on the qualifying volume of oil produced from eligible vertical and horizontal oil wells. Refer to the royalty section for the qualifying volumes.

2. Other Oil Tax Programs

New or Expanded Waterflood Projects
Refer to Information Circular PR-IC06.

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

Oil Well Reactivation Program
Oil production from qualifying reactivated oil wells is subject to a production tax rate of 0% for a period of 5 years from the date of reactivation. The applicable new oil production tax rate will apply thereafter. Eligibility rules are the same as those outlined in the oil royalty section.

High Water-Cut Program
Refer to Information Circular PR-IC12.

Incremental oil resulting from qualifying investments made to improve the recovery rates of eligible high water-cut oil wells will receive third tier oil production tax rates with an SRC of 2.5%. Eligibility rules are the same as those outlined in the oil royalty section.

Workover Reclassification Program
Refer to Information Circular PR-IC07.

The tax classification of any well that produces old oil (pre-1974) may be reclassified to new oil for production tax purposes if the operator undertakes an approved major workover to improve oil recovery rates.

3. Enhanced Oil Recovery (EOR) Royalty Regime

Refer to Information Circulars PR-IC11 and PR-IC11A.

Like the Crown royalty regime, the Saskatchewan enhanced oil recovery production tax regime is a cost sensitive system that recognizes the higher investment and operating costs associated with EOR projects. The EOR production tax 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 production tax rate structures exist, one for projects that commenced operation prior to April 1, 2005 and the other for projects or project expansions that commenced operation on or after April 1, 2005. In both cases, the production tax level is sensitive to project profitability and investment payout. The EOR production tax rate is calculated as follows:

	Projects Commencing Before April 1, 2005	Projects Commencing On or After April 1, 2005
Before Payout	0%	0%
After Payout	(23 % of Net Revenue) - SRC	8% of Net Revenue

Where:

Net Revenue = Gross Revenue minus allowable costs (Gross Revenue is the total value of EOR oil production from a project).

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. The SRC does not apply to production from new or expanded projects commencing on or after April 1, 2005.

3. Corporate Taxes

Corporate Income 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

Large corporations that have more than $10 million in paid-up capital allocated to Saskatchewan are assessed a Corporation Capital Tax (CCT) equal to 0.6% of paid up capital in excess of $10 million. Deductions for determining taxable paid-up capital include a standard exemption of $10 million, an additional variable exemption up to $10 million, investment allowance and deferred exploration and development expense deductions.

Resource Surcharge

Like the CCT, the Resource Surcharge is only applicable to corporations with more than $10 million in paid-up capital allocated to Saskatchewan. However, for purposes of the surcharge, the deferred exploration and development expense deduction is not allowable in determining paid-up capital.

The Resource Surcharge, for oil and gas corporations, equals the corporation's value of Saskatchewan resource sales multiplied by the applicable surcharge rate minus the CCT liability. The applicable surcharge rate is 2% of resource revenues for production from oil and gas wells with a finished drilling date on or after October 1, 2002 and for incremental oil related to new or expanded enhanced oil recovery projects or waterflood projects having a commencement date on or after October 1, 2002. The surcharge rate for all other oil and gas is 3.6%.

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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 ROYALTY 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 m^3/month 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 m^3/month and 300 m^3/month, a rate between 10.4% and 22.4% is applied.

Third Tier Oil

The third tier 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 m^3/month 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] x 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 (prior to January 1, 2009)

K = 0.0

Low Productivity Wells

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

ii. OIL ROYALTY 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 Royalty Programs), Major Workover Incentive, Injection Well Incentive and the Holiday Oil Volume Account.

New Well Holiday Oil Volume (January 1, 2004 to January 1, 2009)

New wells drilled on or after January 1, 2004 and prior to January 1, 2009, 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. The minimum holiday volume is 500 m^3. No application is required.

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

If D < 2 kilometres: HOV = A x D + B

If D > 2 kilometres: HOV = A' x 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	=	1.7 x P + 230
B	=	3130 - 13.6 x P
A ‘	=	0.17 x P + 106.9
B ‘	=	3163 - 10.9 x P
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 (January 1, 2004 to January 1, 2009)

Any new well drilled on or after January 1, 2004 and prior to January 1, 2009, 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 unit tracts in which the well is located, as determined under regulation. Vertical wells must be converted to injection prior to producing 250 m^3. Horizontal wells must 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. Newly drilled vertical wells may be assigned up to 3,000 m^3 holiday oil volume.

2. Horizontal Well Royalty Programs

Horizontal Well: Holiday Oil Volume (January 1, 2004 to January 1, 2009)

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 on or after January 1, 2004 and prior to January 1, 2009, earns a holiday volume of 10,000 m^3. The first horizontal leg drilled from a horizontal well on or after January 1, 2004 and prior to January 1, 2009 earns a holiday volume of 3,000 m^3. The volumes 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 Oil Royalty Programs

Marginal Well Major Workover Holiday Oil Volume (January 1, 2004 to January 1, 2009)

Any marginal well where a major workover is completed on or after January 1, 2004 and prior to January 1, 2009, 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 3 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 (TTEF) is applied to old oil and new oil production from the approved project area to determine a project's Third Tier EOR Production. The TTEF is determined by Industry, Economic Development and Mines, at the time of project approval, based on the following formula:

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

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 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 Tax

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

B. Crude Oil Freehold 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 Oil Royalty Programs".

VI YUKON

The Yukon Oil and Gas Royalty Regulation is still being drafted and will be released for public discussion before promulgation. The Yukon has publicly stated that it intends to establish an ad valorem royalty structure for oil and gas which would include the following characteristics:

- Price sensitive royalty rates
- Lower royalty rates on initial production
- Administrative simplicity as an important principle.

The current gas production in the Kotaneelee field in the Yukon pays royalty at a rate set under the Canada Oil and Gas Lands Regulations, and that royalty rate will be grandfathered for this production.

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

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 IX – Federal.

VIII FEDERAL

1. Royalties

Natural resources in Canada are owned by the Provinces; as such, royalties fall under provincial jurisdiction. With the exception of the Yukon, 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. The Yukon will administer royalties under the pending Yukon Oil and Gas Royalty Regulation as previously noted in section VI.

Federal royalties can be categorized as applying to either:

1. Frontier Lands
2. 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 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 after 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, and a return allowance. Payout is calculated on a working interest basis, by project.

Natural Gas 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 2003, the Federal Government announced changes to the federal tax system for the 2003 - 2007 period. The net federal tax rate is 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 23% net tax rate applicable for 2006.

A federal surtax on corporate tax payable is currently in effect. Corporations with taxable capital of $75 million or more are subject to a 4% surtax rate. The surtax rate progressively declines from 4% to 0% for corporations with taxable capital between $75 and $50 million.

In the 2006 budget, the federal government announced it would eliminate the corporate surtax for all corporations in 2008.

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 is being 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 are subject to a reduced federal tax rate of 12% on the first $300,000 of net income. The 2006 federal budget increased the net income eligible for the reduced rate from $300,000 to $400,000 as of January 1, 2007. Further, the tax rate will be reduced from 12% on net income to 11.5% in 2008 and 11% in 2009.

Example of Simplified Tax Calculation Format

Gross Revenue

- Operating & Lifting Costs
- Non-Crown Royalty
- General & 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 BETWEEN 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 \$200 per 10^3m^3. The select prices in effect for 2006 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 100 m^3 per month. In the graphs depicting production, heavy oil has price fixed at \$250/m^3, while non-heavy oil has a fixed price of \$300/m^3. The select prices in effect for 2006 were used in the calculations.

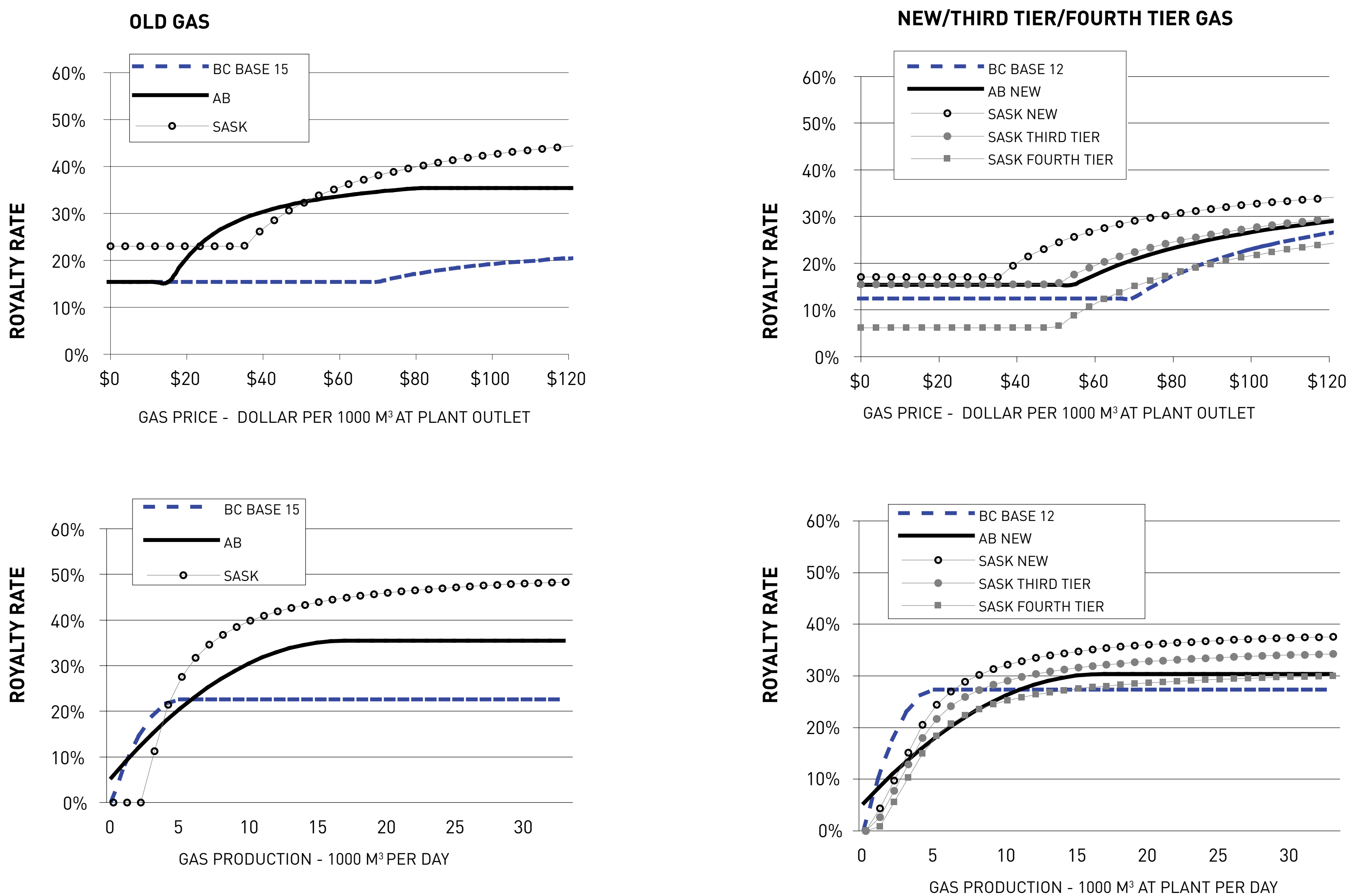

Figure 4: Natural gas royalty rates are a function of well productivity, vintage classification, and price. Alberta and Saskatchewan use the gas plant outlet price in the natural gas royalty calculation. For British Columbia, the gas plant outlet price is reduced by an estimated price differential to obtain the gas plant inlet price used in British Columbia's natural gas royalty rate formula.

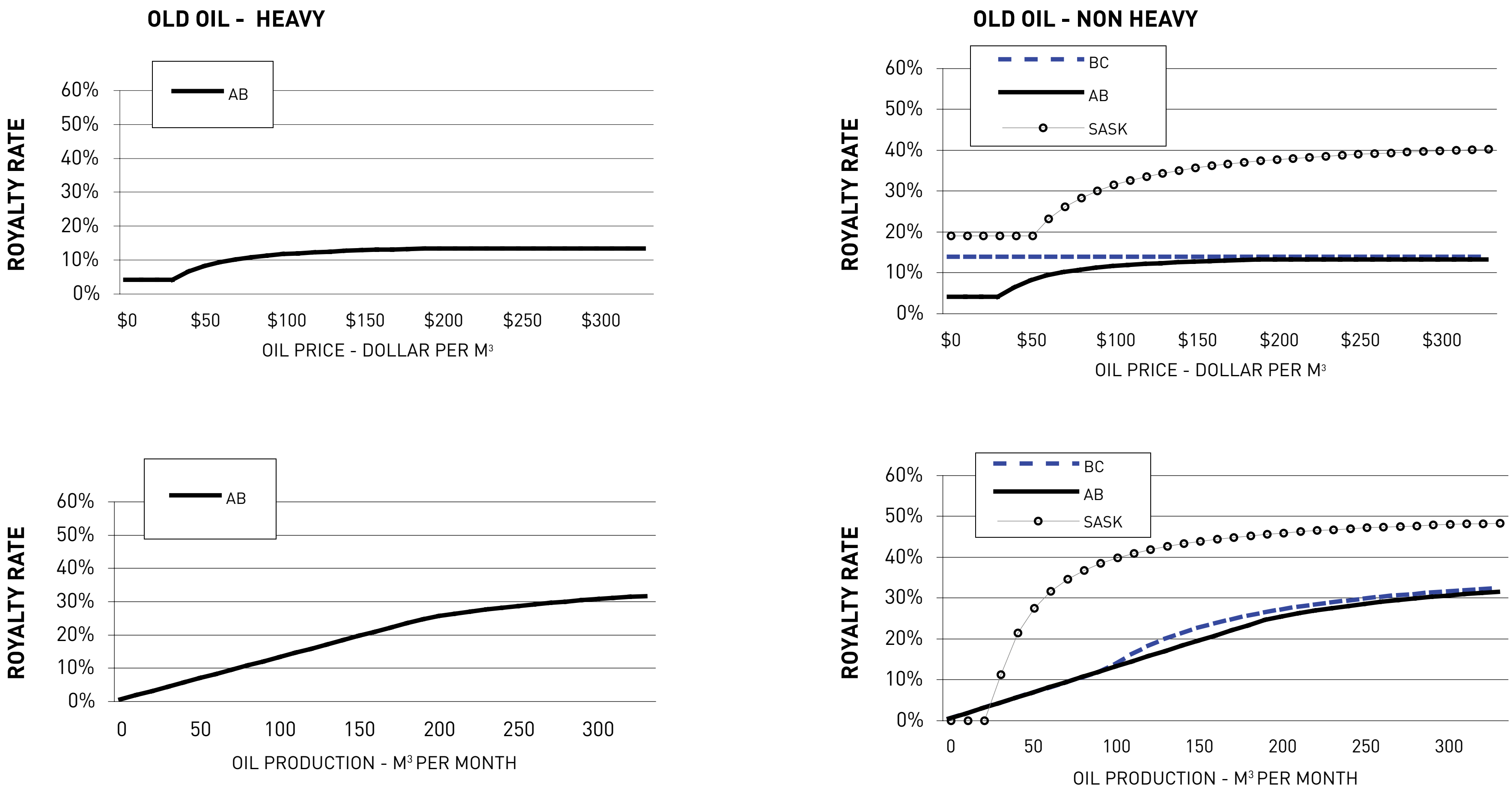

Figure 3: Old oil royalty rates are a function of oil density and wellhead productivity. The Alberta and Saskatchewan old oil royalty formulas also include price sensitivity. All oil produced in the southwest and heavy oil areas of Saskatchewan that would that would have otherwise been classified as old oil has been reclassified to new oil.

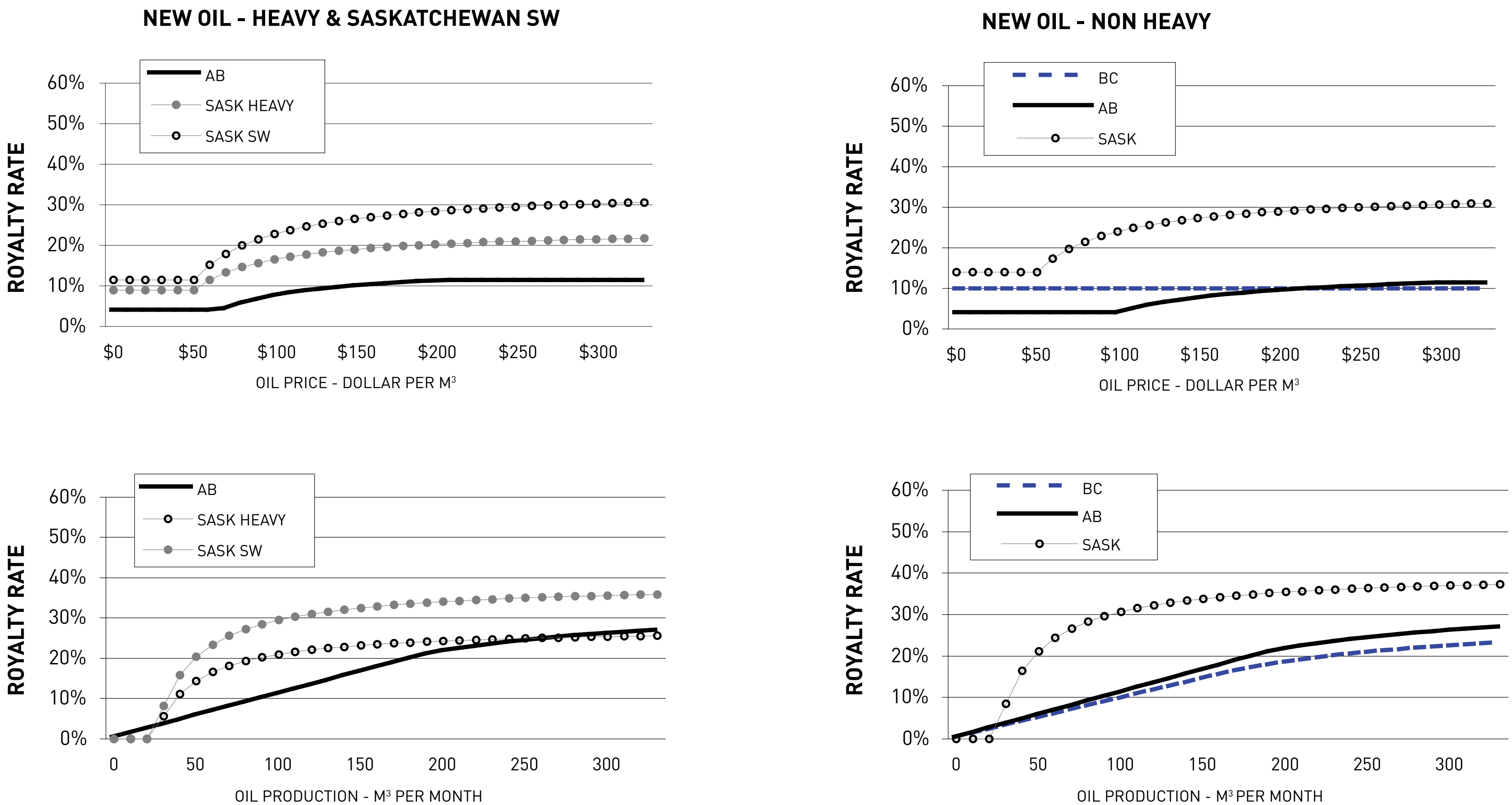

Figure 4: New oil royalty rates are a function of oil density and wellhead productivity. The Alberta and Saskatchewan new oil royalty formulas also include price sensitivity. Saskatchewan has separate categories for heavier crudes under new oil: heavy oil and southwest designated oil. The density of these categories is typically comparable to Alberta's heavy oil.

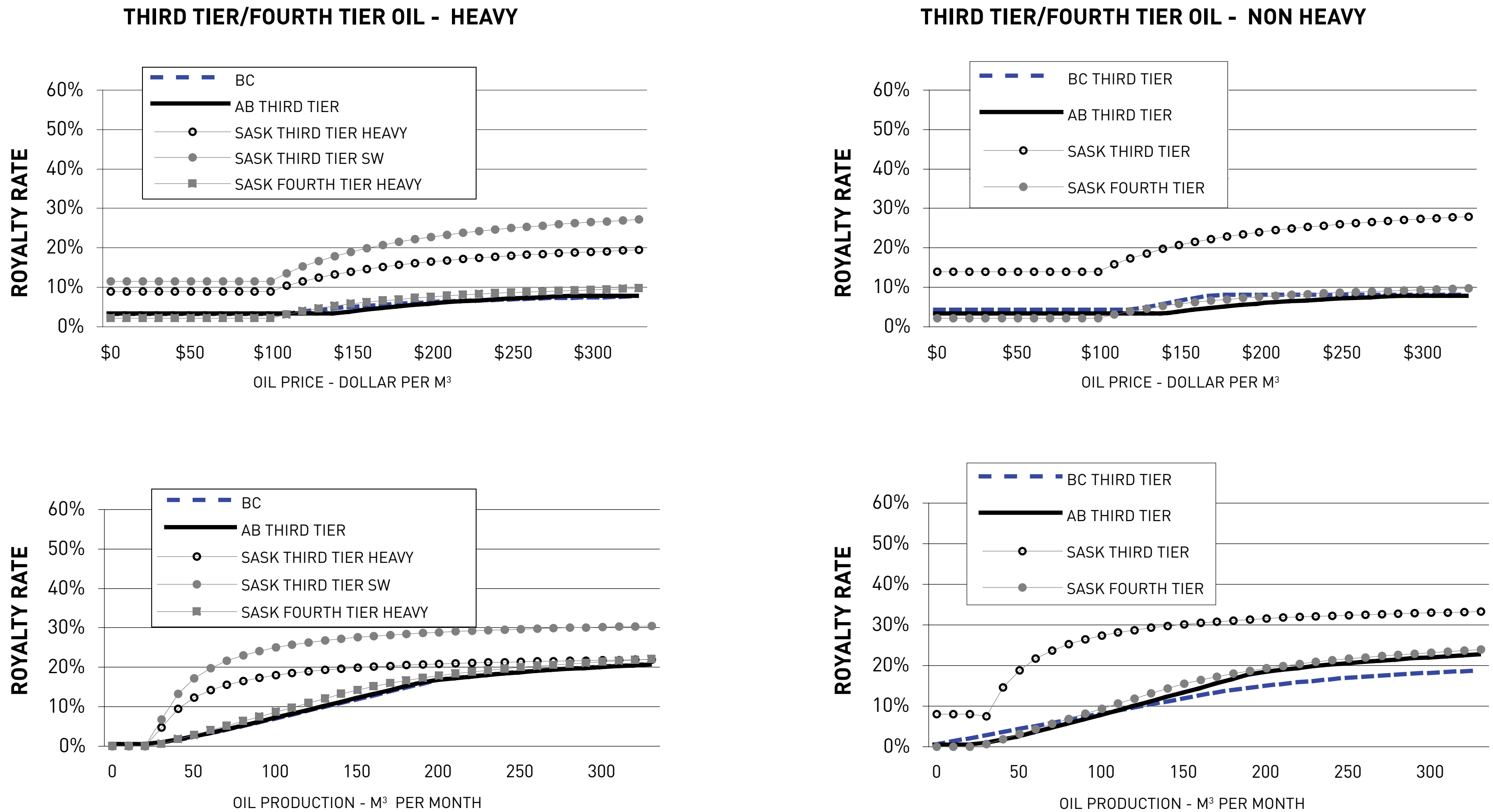

Figure 7: Third tier and fourth tier oil royalty rates are a function of oil density, wellhead productivity and price. Saskatchewan has separate categories for heavier crudes under third tier oil and fourth tier oil: heavy oil and southwest designated oil. The density of these categories is typically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

Note: British Columbia's heavy oil formula was implemented in 1999. The formula is not date-sensitive (one heavy oil formula applies to all wells regardless of drilling date) but is compared to third tier and fourth tier heavy oil since these categories were also implemented in more recent time frames.

X CONTACTS

British Columbia

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Fax: (250) 952-0626/0627

Titles Branch

Information Letters, Land Sales, Titles Administration
Phone: (604) 952-0332
Fax: (604) 952-0331

Department of Provincial Revenue

Resource Revenue Branch

Mineral, Oil and Gas Revenue Branch
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Fax: (250) 952-0191

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Alberta

Alberta Department of Energy

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Information Centre/Library

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North Petroleum Plaza Site
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Edmonton, Alberta T5K 2G8
Phone: (780) 422-9696
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Visit the following websites for more information about Alberta and its energy and mineral resources:

Government of Alberta at: http://www.gov.ab.ca/home/index.cfm
Alberta Energy and Utilities Board at: http://www.eub.ca/portal/server.pt

Saskatchewan

Department of Industry and Resources

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2101 Scarth Street
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Phone: (306) 787-2528 (General Inquiry and Publications)
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