

# OIL AND GAS FISCAL REGIMES

WESTERN CANADIAN PROVINCES AND TERRITORIES

JUNE 2011

*Canada's  
New West Partnership*







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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 (including coalbed methane and shale gas) and natural gas by-products. 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. In the Yukon, the territory or Crown owns the majority of subsurface rights, and in the NWT, Nunavut and northern offshore, the federal government is the owner of the majority of petroleum and natural gas resource 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 western provinces follow a similar process, but their sales dates are less frequent. The federal government provides an annual opportunity to obtain exploration rights in the Northwest Territories, Nunavut and the northern offshore by launching calls for nominations and calls for bids.

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

## 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**

Royalty rates are not date sensitive.

**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 $\geq 890 \text{ kg/m}^3$
Non-heavy Oil	oil with density $< 890 \text{ kg/m}^3$

**ALBERTA**

Royalty rates are not sensitive to density.

## SASKATCHEWAN

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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<sup>3</sup> with an average of approximately 975 kg/m<sup>3</sup>.

**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<sup>3</sup> with an average of approximately 925 kg/m<sup>3</sup>.

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

## MANITOBA

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Manitoba does not classify its oil resources by density.

## II Contributions of Western Canadian Energy Investment on Canada's Economy

The fiscal regimes for the Western Canadian provinces play a critical role in determining the competitiveness of Western Canada's energy industry, while at the same time providing a return for the people of western Canada for the development of their resources, and tax revenue for the federal government.

"A well designed royalty system endeavours to strike the right balance between returning a share of the profits to the resource owner, while encouraging the development of the resource to create jobs and economic growth." – Government of Alberta: Energy Economics, Understanding Royalties

The following section examines trends in energy investment and development in western Canada in an attempt to highlight the importance of the industry on western Canada's economy, and the Canadian economy as a whole.

### Energy Investment Trends in Western Canada

Investment in the energy sector has grown significantly across western Canada, and has contributed tremendously to Canada's economy over the past decade – a trend that is expected to continue into the future.<sup>1</sup> According to Statistics Canada, total energy investment in western Canada (British Columbia, Alberta and Saskatchewan) has increased from \$25.7 billion in 2003 to \$38.3 billion in 2010 – an increase of 49%. Total energy investment in western Canada is expected to reach just over \$40 billion in 2011 – an increase of 7% from 2010, and 21% from the global economic downturn in 2008, which saw western Canadian energy investment fall by 39% (or \$21 billion) between 2008 and 2009.

To put the level of energy investment into a broader Canadian context, the total amount of capital that has been invested in the energy sector in western Canada amounts to over 83% of the investment made in Canada's overall energy industry, and 13% of the total investment made in all sectors of Canada's economy.

Alberta's energy sector is the largest of the western Canadian provinces and, with a 30% increase in capital investment since 2003,<sup>2</sup> energy investment is expected to top C\$26 billion in 2011.<sup>3</sup> The energy sectors in British Columbia and Saskatchewan are comparatively smaller than Alberta's but have seen steeper rates of growth. Investment in British Columbia's energy sector has ballooned 180% since 2003, and is expected to rise to C\$8.6 billion in 2011. In Saskatchewan, investment in the energy sector has grown almost 60%, and is expected to top C\$5.7 billion in 2011.<sup>4</sup>

1 'Western Canada' refers to British Columbia, Alberta and Saskatchewan and does not include the Northwest Territories, Manitoba or the Yukon.

2 Investment in the energy sector includes both mining and oil and gas.

3 Statistics Canada.

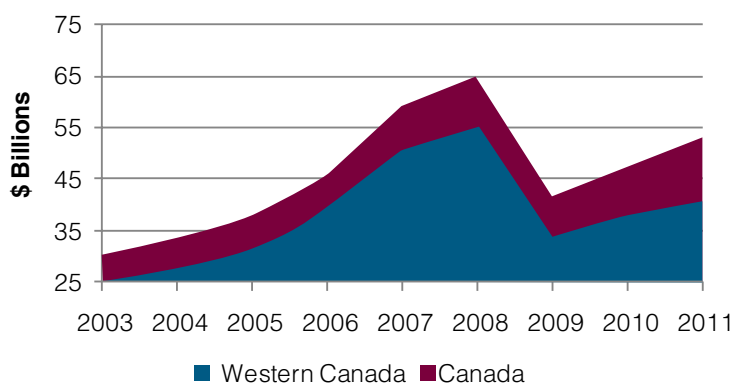
4 Statistics Canada.



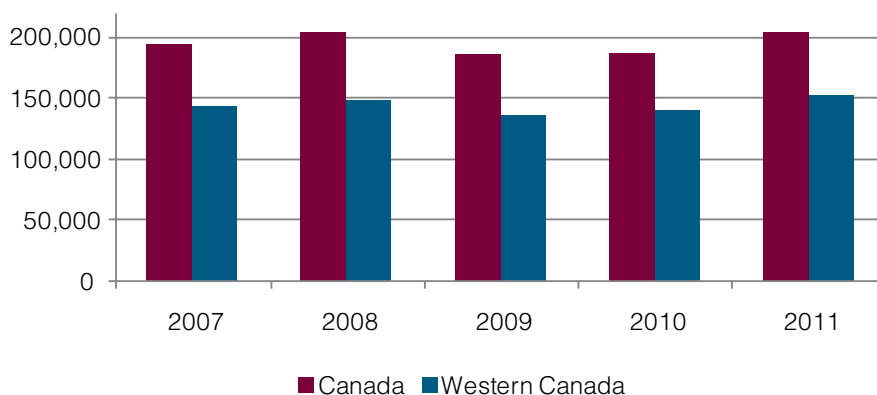
## Western Canada Energy Investment and its Impact on Canadian Labour Markets

The robust activity in western Canada's energy industry has had a profound impact on Canada's labour markets. According to Statistics Canada, employment in western Canada's energy industry has increased from 107,000 people in 2003 to 137,000 people in 2010 – an increase of 29%. Western Canada saw employment in the energy sector top 145,000 jobs just before the economic downturn in late 2008, representing approximately 75% of all energy jobs in Canada. Since the recession, jobs within the energy sector in western Canada have rebounded, with total employment expected to reach 149,000 by 2011.

### Capital Investment in Energy

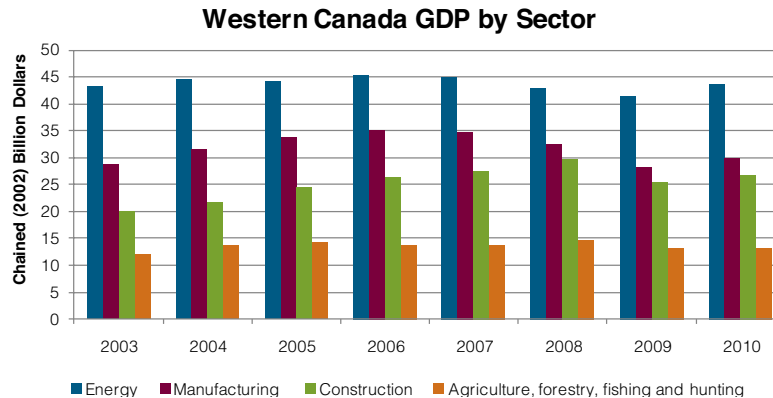


### Western Canada Energy Employment

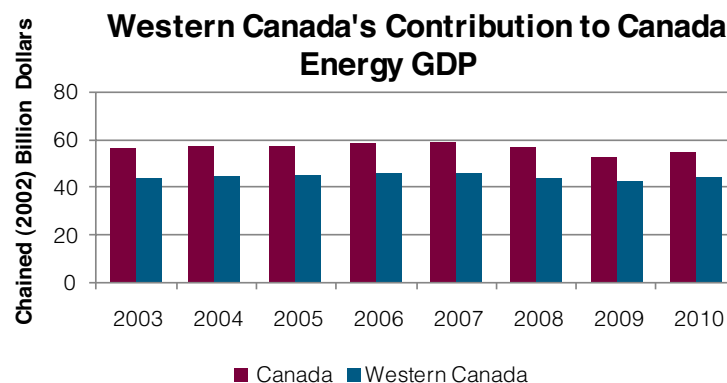


## Western Canada Energy Investment and its Impact on Canada's Economy

The impact of the energy sector on western provinces' gross domestic product (GDP) has also been significant. In western Canada, the energy sector is the single largest goods producing sector and constitutes approximately 12% of its total GDP.<sup>5</sup>



While Alberta, British Columbia and Saskatchewan's share in Canada's total GDP was, on average, 30% between 2003 and 2010, western Canada's share of total energy GDP in Canada was considerably larger.<sup>6</sup> Since 2003, on average, the western provinces' energy GDP has constituted 79% of Canada's total GDP from the energy sector.<sup>7</sup>



## Anticipated Impacts of Western Canada Energy Investment on the future of Canada's Economy

According to the Canadian Energy Research Institute (CERI) 2009 report on the economic impacts of the petroleum industry on Canada over the next 25 years, "oil and gas companies will invest C\$1.07 trillion (2008 dollars), which will result in incremental growth in gross domestic product (GDP) for the Canadian economy of C\$3.5 trillion". Of that total, the impact of upstream oil and gas activities in western Canada on GDP will be over C\$3.2 trillion. In all, energy investment in the western provinces will total over 92% of Canada's total energy GDP with Alberta's provincial share topping 71.8%, British Columbia's share will be 13.4% and Saskatchewan will be 6.8%.

<sup>5</sup> Statistics Canada.

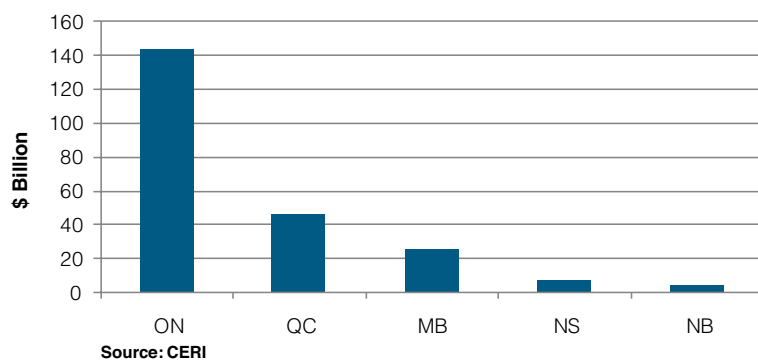
<sup>6</sup> Energy GDP refers to the GDP resulting from the mining and oil and gas extraction sector.

<sup>7</sup> Statistics Canada.

While the western provinces will enjoy the lion's share of the increased GDP, other provinces will also benefit. For example, developments in western Canada's upstream oil and gas sector will lift Ontario's GDP by \$140 billion over the next 25 years.

Capital investment in the energy sector in western Canada will have a huge impact on the total taxes paid to the federal government over the next 25 years. According to CERI, the oil and gas sector in the western provinces will have a total impact on federal taxes of over C\$400 billion.

### Total Impact of Western Canada's Energy Sector on Provincial GDP, 2010-2035



Notwithstanding the results of the 209 CERI study, recent technological developments in unconventional oil and gas production point to increased activity in western Canada's energy industry. Technological advancements in multistage horizontal drilling have re-invigorated mature oil fields across western Canada. Production of tight oil in the Bakken and Cardium formations has mushroomed over the past several years. From a low of 1,000 barrels per day of production in 2004, the Canadian Bakken, located in Saskatchewan, has reached around 60,000 barrels per day of production in 2010, with potential recoverable barrels estimated at over 1 billion barrels.<sup>8</sup> A similar trend is occurring in the Cardium, Alberta's largest and oldest oil reservoir.<sup>9</sup>

Unconventional gas production is also seeing a renaissance with new drilling technology. According to Wood Mackenzie, natural gas production from the shale gas plays in Northeast British Columbia is estimated to be 1.0 billion cubic feet per day in 2010 with potential to grow to 8.3 billion cubic feet per day by 2020.<sup>10</sup> Given that natural gas demand in British Columbia is forecast to only grow to 1.0 billion cubic feet per day by 2020, there is potentially 6.8 billion cubic feet per day of incremental gas available for export markets by 2020. The Kitimat liquefied natural gas facility in British Columbia is one response to the higher levels of supply in Western Canada. Expected to be operative in 2015, the facility has an initial proposed capacity of 0.7 billion cubic feet per day of liquefied natural gas output.<sup>11</sup>

8 Wood Mackenzie, "The Emergence of the Canadian Bakken," September 2010.

9 Macquarie Equities Research, "Cardium Redux: Cracking our Cardium Six Pack" November 2010.

10 Wood Mackenzie, "North American Gas Service: Long Term View-Supply and Demand," April 2011.

11 National Energy Board.

<b>B.C Shale Gas (Bcf/day)<sup>1</sup></b>		
	<b>2010</b>	<b>2020</b>
<b>Production</b>	1.0	8.3
<b>Demand</b>	0.5	1.0
<b>Exports</b>	0.5	7.3
<b>Incremental Gas by 2020</b>	6.8	

Rising global demand for crude oil and refined products such as diesel, brought on by continued strength emerging economies overseas, has led to an increase in North American crude oil prices since the global economic downturn in late 2008 and 2009, which has improved oil sands economics. In CERI's updated 2010 report, Economic Impacts of New Oil Sands Projects in Alberta (2010-2035), the estimated investment in the oil sands is now expected to top C\$2,077 billion between 2010-2035, which will result in an estimated C\$2,106 billion in GDP for Canada's economy, C\$311 billion in taxes to the federal government and C\$105 billion in taxes to the Alberta provincial government. Alberta will also receive C\$350 billion in royalties over the 25-year period.

## III 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.

$$R\% = [400 + 15 \times (RP - 50)] / RP \text{ (to a minimum of 8\%)}$$

##### 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.

$$R\% = [750 + 25 \times (RP - 50)] / RP \text{ (to a minimum of 15\%)}$$

##### 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%.

$$R\% = [12 \times SP + 40 \times (RP - SP)] / RP \text{ (not below 12\% and not more than 27\%)}$$

##### 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%.

$$R\% = [9 \times SP + 40 \times (RP - SP)] / RP \text{ (not below 9\% and not more than 27\%)}$$

##### Where:

R% = Royalty rate

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

SP = Select Price (\$/10<sup>3</sup>m<sup>3</sup>) set by the Royalty Administrator. The select price is \$50 currently until further notice.

##### Low Productivity Wells

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

$$R\% = Rc\% - Rc\% \times [(5000 - ADV) / 5000]^2$$

**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**

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

**Sulphur**

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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**

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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.

**Gas Cost Allowance**

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

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

**iii. GAS ROYALTY PROGRAMS**

**1. Natural Gas Royalty Reduction**

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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**

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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) if the well has a spud date after August 31, 2009, the well has a depth of at least 2,500 metres for vertical wells and 1,900 metres for horizontal wells;

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 FOR WELLS SPUDED  
AFTER AUGUST 31, 2009**

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	4,830	2,500	0	1,725
3,000	2,415	690	3,000	863	748
3,500	2,760	805	3,500	1,236	863
4,000	3,163	920	4,000	1,668	978
4,500	3,623	1,035	4,500	2,156	1,150
5,000	4,140	1,150	5,000	2,731	1,265
5,500	4,715		5,500	3,364	
WEST SWEET			EAST SWEET		
Depth	Cumulative Value	Incremental Value	Depth	Cumulative Value	Incremental Value
Metres	\$000	\$/Metre	Metres	\$000	\$/Metre
2,500	0	4,370	2,500	0	1,610
3,000	2,185	633	3,000	805	690
3,500	2,501	690	3,500	1,150	805
4,000	2,846	805	4,000	1,553	920
4,500	3,249	920	4,500	2,013	1,035
5,000	3,709	1,035	5,000	2,530	1,150
5,500	4,226		5,500	3,105	

**ROYALTY CALCULATION:**

The deep deduction amount is calculated as:

CV + AD

**Where:**

CV means the Cumulative Value shown opposite the Table Depth of the deep well event.

Table depth means the deep well depth of the deepest well event rounded down to the nearest 500 metres

AD means the incremental value that is shown opposite the table depth of the deepest well event multiplied by the positive difference between the deep well depth of that well event and the table depth of that well event.

**Example**

The table depth for the deepest well event rounded down to the nearest 500 metres for a deep sour well in the West area spudded after August 31, 2009 is 3,200 metres.

Royalty Credit = 2,415,000 + (3,200 - 3,000) x 690 = \$2,553,000

### 3. Deep Re-entry Royalty Program

A deep re-entry deduction amount may be provided to a deep re-entered well. 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.

$$\text{Royalty Credit} = 90,000 + (1000 - 300) \times 300 = \$300,000$$

### 4. Deep Discovery Well Royalty Program

The Deep Discovery Program provides the lesser of a three year royalty holiday or 283,000,000 m<sup>3</sup> 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<sup>3</sup> 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 or 12 formulas. Each marginal well also gets a low productivity reduction factor against the royalty percentage in accordance with the following formula:

$$[(25,000 - S) / 25,000]^2$$

**Where:**

S is equal to the lesser of the average daily natural gas production volume for the marginal well event in the producing month and 25, 000 m<sup>3</sup>;

**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<sup>3</sup> for every metre of well depth if the well event is in an exploratory wildcat well and 11 m<sup>3</sup> 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 ultramarginal wells is based on the Base 9 or 12 formulas. Each ultramarginal well also gets a low productivity reduction factor against the royalty percentage in accordance with the following formula:

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

**Where:**

S is equal to the lesser of the average daily natural gas production volume for the ultramarginal well event in the producing month and 60,000 m<sup>3</sup>.

**7. Summer Royalty Program**

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.

### 8. The Infrastructure Royalty Credit Program

Through the Infrastructure Royalty Credit Program, oil and gas companies can apply for a credit to the royalties they would otherwise pay to the Province. This credit can be as much as 50 per cent of the cost of constructing roads, pipelines or associated facilities.

**The purposes of the program are to:**

Facilitate increased oil and gas exploration and production in under-developed areas;  
and

Extend the drilling season to allow for year-round activity.

### 9. Net Profit Royalty Program

The Net Profit Royalty Program intends to stimulate development of natural gas and oil resources by sharing the capital risk of successful developments and recognizing the long-lead times associated with these developments. The program is governed under the *Net Profit Royalty Regulation*, which came into effect in May, 2008.

The program is distinct from existing targeted royalty programs. It will promote the development of resources which are unlikely to be otherwise developed by focusing on resources that are remote from existing infrastructure or are technically complex.

### 10. Coalbed Methane

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<sup>3</sup> per day for conventional gas wells, to 17,000 m<sup>3</sup> 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.

## 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<sup>3</sup>/month. The marginal rate applied to production above 95 m<sup>3</sup>/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<sup>3</sup>/month. The marginal rate applied to production above 159 m<sup>3</sup>/month is 30%.

### Third Tier Oil

The third tier oil royalty rate is the product of the Price Factor and the production above this threshold, the Price Factor progressively increases to a maximum of 2.0 at a wellhead price of \$175/m<sup>3</sup>.

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

### Heavy Oil

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

Heavy oil wells producing at rates less than 20 m<sup>3</sup> per month are not subject to a royalty. At a \$250/m<sup>3</sup> 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<sup>3</sup>/month and 200 m<sup>3</sup>/month. The marginal rate applied to production above 200 m<sup>3</sup>/month is 26.4%.

### Low Productivity Wells

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

#### i. OIL ROYALTY FORMULAS AND RATES

R% = Royalty rate

Q = Production (m<sup>3</sup>/month)

#### Old Oil and New Oil:

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

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

#### Old Oil (pre-November 1975)

K = 792

A = 11.4

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

C = Production threshold = 95 m<sup>3</sup>/month

**New Oil (post-October 1975)**

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- K = 1058
- A = 23.9
- B = Marginal rate on production above production threshold = 30%
- C = Production threshold = 159 m<sup>3</sup>/month

**Third Tier Oil (post-December 1999)**

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- R% =  $P \times (Q / K) \times 100$  when  $Q \leq C$
- R% =  $P \times [(A + B \times (Q - C)) / Q] \times 100$  when  $Q > C$
- K = 2645
- A = 9.56
- B = Marginal rate on production above production threshold = 12%
- C = Production threshold = 159 m<sup>3</sup>/month
- P = Price Factor which is the lesser of:
  - (a)  $\frac{1 + 3.5 \times (\text{Wellhead Price} - \text{Third Tier Oil Threshold Price})}{\text{Wellhead Price}}$
  - (b) 2

The Third Tier Oil Threshold Price has been set at \$125/m<sup>3</sup> 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)**

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- R% = 0 when  $Q < 20$
- 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 = Marginal rate on production above maximum production threshold = 11%
- C1 = Minimum production threshold = 20 m<sup>3</sup>/month
- C2 = Maximum production threshold = 200 m<sup>3</sup>/month
- P = Price Factor which is equal to:

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

The Heavy Oil Threshold Price has been set at \$110/m<sup>3</sup> 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.

## 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  $P \leq \$50/10^3\text{m}^3$

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

#### Non-Conservation Gas

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

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

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  $P \leq 159 \text{ m}^3/\text{month}$

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

## 3. Corporate Income Taxes

### Basic Corporate Tax

The current general corporate income tax rate is 10%. The rate applicable to the first \$500,000 of active business income of a Canadian controlled private corporation is 2.5%.

## 4. Carbon Tax

The carbon tax applies to the purchase or use of fossil fuels within the province. The amount of GHGs emitted when a unit of fossil fuel is burned depends fundamentally on the chemical make-up of the fuel, particularly on the amount of carbon in the fuel. That fact allows for a relatively simple administrative process for applying the carbon tax:

Administratively, the carbon tax is applied and collected at the wholesale level in essentially the same way that motor fuel taxes are currently applied and collected, except natural gas which is collected at the retail level. The tax rates on July 1, 2011 are equal to \$25 per tonne of CO<sub>2</sub> equivalent emissions, increasing by \$5 per tonne for 2012 to \$30 per tonne.

## 5. Harmonized Sales Tax

The government of British Columbia implemented a Harmonized Sales Tax (HST) on July 1, 2010.

A 7% BC rate has been added to the 5% federal Goods and Services Tax (GST). This combined 12% tax is called the HST.

The introduction of the harmonized sales tax is an essential step to make BC businesses more competitive, encourage new investment, improve productivity, and reduce administrative costs for BC taxpayers and businesses. Most importantly, harmonization will generate economic growth and, over time, create jobs and generate more revenue to sustain and improve crucial public services.

## IV ALBERTA

### 1. Royalties

#### A. Natural Gas

##### Objective

To retain a share of the production as royalty for Albertans the resource owners. The natural gas royalty rate is sensitive to the market price and well productivity, with the exception of an initial 5% royalty rate for new wells.

##### Natural Gas

- 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 Well Event Average Royalty Rate (WEARR) set monthly for each well event, which is the weighted average of the royalty rates for the components in the gas stream at the applicable well event. These in stream components (ISCs) include Methane (C<sub>1</sub>), Ethane (C<sub>2</sub>), Propane (C<sub>3</sub>), Butanes (C<sub>4</sub>), and Pentanes-Plus (C<sub>5+</sub>).

##### ISC's and Natural Gas Liquids

- For methane, the maximum and minimum royalty rates are 36% and 5%, respectively. The royalty rate is the sum of a price component and a quantity component:  
R% = Price Component (rp) + Quantity Component (rq)
- Ethane is levied at the same royalty rate as methane. The royalty rate for propane and butane is 30%, and 40% for pentanes-plus.
- The above royalty rates for natural gas liquid components apply as an ISC or extracted liquid.

##### Sulphur

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

##### Valuation for Natural Gas and ISCs

- Effective the January 2011 production month, purchase prices at the Alberta Market Hub on the Natural Gas Exchange (NGX) will be used to calculate the gas reference price for all Alberta production. The gas reference price will be used to value all in-stream components of natural gas.

##### Valuation for Natural Gas Liquids

- For Crown royalty purposes, liquid ethane is converted to an energy equivalent (expressed in gigajoules) and valued at the gas reference price.
- 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 and fractionation allowances if produced liquids are in a mix.

#### i. GAS ROYALTY FORMULAS AND RATES

$$R\% = \text{WEARR}$$

= Weighted average of royalty rates for ISC's in the gas stream at the applicable well event.

**ISC Royalty Rates****Methane and Ethane**

$R\% = \text{Price Component (rp)} + \text{Quantity Component (rq)}$

$5\% \leq R\% \leq 36\%$

**PRICE COMPONENT ( $r_p$ )****Par Price (\$/GJ)** **$r_p$** 

$PP \leq 5.25$	$(PP - 4.50) \times 0.045 \times 100$
$5.25 < PP \leq 9.00$	$[((PP - 5.25) \times 0.02) + 0.03375] \times 100$
$PP > 9.00$	$[((PP - 9.00) \times 0.01) + 0.10875] \times 100$

$R_p$  can be negative, and has a 30% maximum.

The par price (PP) is set monthly and is equal to the current months ISC methane price.

**QUANTITY COMPONENT ( $r_q$ )****Quantity ( $10^3\text{m}^3/\text{d}$ )** **$r_q$** 

$ADP \leq (6 \times DF)$	$(ADP - (4 \times DF)) \times (0.05/DF) \times 100$
$(6 \times DF) < ADP \leq (11 \times DF)$	$[(ADP - (6 \times DF)) \times (0.03/DF) + 0.1] \times 100$
$ADP > (11 \times DF)$	$[(ADP - (11 \times DF)) \times (0.01/DF) + 0.25] \times 100$

$R_q$  can be negative, and has a 30% maximum.

ADP is the average daily gas production ( $10^3\text{m}^3/\text{day}/\text{well}$ ) for the production month and is calculated as follows:

$ADP = (\text{Production Volume} \times 24) / (\text{Hours on Production})$

For well events producing solution gas, the ADP is based on the total oil and gas production. Oil production is converted to a gas equivalent volume as follows:  
 $(\text{Oil Volume, m}^3) \times 1.0686 = \text{Gas Equivalent Volume in e}^3\text{m}^3$

DF is a depth factor based on the measured depth (MD) of a well where:

$DF = 1$  for  $MD \leq 2000$  metres;

$DF = (MD/2000)^2$  for  $MD > 2000$  metres; and,

The depth factor is capped at 4.

**Propane, Butane and Pentanes-Plus**

$R\% = 30\%$  for propane and butane.

$R\% = 40\%$  for pentanes-plus.

**ii. ROYALTY ADJUSTMENTS****1. New Well Royalty Rate**

Refer to Alberta Energy Information Letter 2009-23.

New gas wells and some wells recommencing production are subject to a maximum 5% royalty rate for all products. This royalty rate applies for 12 production months, subject to a 500 million cubic foot gas equivalent volume cap.

**Qualifying Wells**

- The well must be spud on or after April 1, 2009.
- The well must be classified as an oil, gas or crude bitumen well when it commences or recommences production.
- Must be subject to the payment of royalty under the Petroleum Royalty Regulation, 2009, the Natural Gas Royalty Regulation, 2009 or section 27 of the Oil Sands Royalty Regulation, 2009.



- A well recommencing production on or after April 1, 2011 can qualify if it did not produce crude oil or gas (other than excluded production) in the 36 months prior to commencing production.
- A well recommencing production on or after April 1, 2011 can also qualify if it did not produce crude oil or gas (other than excluded production) from January 1, 2009 to March 31, 2011, and average monthly production is less than 100 m<sup>3</sup> for:
  - all producing months in the January 1, 2007 to December 31, 2008 period if the well produced for three months or less during that period, or
  - the last three producing months in that period if the well was on production for more than three months.
- A 1.0686 conversion factor is applied to gas production to determine oil equivalent volume:  
 $(\text{Gas Volume, e}^3\text{m}^3) / 1.0686 = \text{Oil Equivalent Volume in m}^3$

## 2. Natural Gas Deep Drilling Program (NGDDP)

The royalty rate on gas and products recovered from a qualified well event is 5%. This rate applies for five years after the finished drilling date, subject to a value cap. The value cap includes a measured depth amount, and if applicable, an amount for additional laterals.

### Measured depth amount:

This is determined from Table 1 based on the measured depth of the deepest producing interval in the well.

### Amount for additional laterals:

Wells that have additional legs receive an additional amount based on the sum of the lengths, in metres, of all other laterals in the well from the kick-off point of each lateral to the perforation that is furthest from the kick-off point. This amount is determined from Table 2.

The maximum value of the NGDPP benefit is \$8 million for development wells and \$10 million for exploration wells, regardless of the number of producing zones.

### Qualifying Wells

To qualify for the NGDDP, a well must:

- Commence spudding or deepening on or after May 1, 2010.
- Be drilled into a producing zone, the base of which is greater than 2,000 metres vertical depth.

Measured Depth (metres)	Table 1: NGDDP Royalty Adjustment Per Well Development Wells Benefit per metre drilled in the depth range (\$/metre)			
	>2,000 – 3,500	>3,500 – 4,000	>4,000 – 5,000	>5,000
>2,000	\$625			
>3,000	\$625			
>3,500	\$625	\$2,500		
>4,000	\$625	\$2,500	\$2,500	
>4,500	\$625	\$2,500	\$2,500	
>5,000	\$625	\$2,500	\$2,500	\$3,000

Measured Depth (metres)	Table 1: NGDDP Royalty Adjustment Per Well Exploratory Wells Benefit per metre drilled in the depth range (\$/metre)			
	>2,000 – 3,500	>3,500 – 4,000	>4,000 – 5,000	>5,000
>2,000	\$625			
>3,000	\$625			
>3,500	\$625	\$2,500		
>4,000	\$625	\$2,500	\$3,125	
>4,500	\$625	\$2,500	\$3,125	
> 5,000	\$625	\$2,500	\$3,125	\$3,750

Table 2: Benefits for Additional Laterals	
Qualifying true vertical depth of the well event in metres	Benefit per drilled metre (\$/metre)
< 3,500	\$625
>= 3,500	\$2,500

### iii. 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.

### iv. GAS ROYALTY PROGRAMS

#### 1. Transitional Royalty Rates

The transitional royalty framework for oil and gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. The transition option reduces the maximum royalty rate for methane and ethane to 30%. Only wells with a measured depth between 1,000 and 3,500 metres are eligible. For wells under transitional royalty rates, royalty clients may elect the current royalty framework by February 15, 2011. In this case, the change is effective the January 2011 production month. Effective January 1, 2011, no new wells will be eligible for the transitional royalty rates.

The transitional royalty rate for methane and ethane is calculated as follows:

$$R\% = \text{Price Component (rp)} + \text{Quantity Component (rq)}$$

$$5\% \leq R\% \leq 30\%$$

#### PRICE COMPONENT ( $r_p$ )

Par Price (\$/GJ)	$r_p$
$PP \leq 3.25$	$(PP - 2.00) \times (0.035) \times 100$
$3.25 < PP \leq 5.00$	$[(PP - 3.25) \times 0.005 + 0.0437] \times 100$
$PP > 5.00$	5.25

$R_p$  can be negative, and has a 5.25% maximum.

The par price (PP) is set monthly and is equal to the current months ISC methane price.

#### QUANTITY COMPONENT ( $r_q$ )

Quantity ( $10^3\text{m}^3/\text{d}$ )	$r_q$
$ADP \leq 4$	$[(ADP - 2) \times 0.05] \times 100$
$4 < ADP \leq 9$	$[(ADP - 4) \times 0.02 + 0.10] \times 100$
$ADP > 9$	$[(ADP - 9) \times 0.01 + 0.20] \times 100$

Notes:  $R_p$  can be negative, and has a 25% maximum.

ADP is the average daily gas production ( $10^3\text{m}^3/\text{day}/\text{well}$ ) over a month.

### 2. Shale Gas New Well Royalty Rate

A well that starts producing on or after May 1, 2010 exclusively from shale formations qualifies for a maximum 5% royalty rate on all products. The rate applies for 36 producing months, with no volume limit.

### 3. Coalbed Methane (CBM) New Well Royalty Rate

A well that starts producing on or after May 1, 2010 exclusively from coal areas qualifies for a maximum 5% royalty rate on all products. The rate applies for 36 producing months, subject to a 750 million cubic foot gas equivalent volume cap.

### 4. 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<sup>3</sup> 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.

## **5. Innovative Energy Technologies Program**

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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 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 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 is limited to a maximum of \$10 million. The actual level of funding for each approved project is 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 retain a share of the production as royalty for Albertans the resource owners. The oil royalty rate is sensitive to the market price and well productivity, with the exception of an initial 5% royalty rate applied to new wells.

### i. OIL ROYALTY FORMULAS AND RATES

Effective January 2011, the maximum and minimum royalty rates for conventional oil are 40% and 0% respectively. The royalty rate is the sum of a price component and the quantity component:

$$R\% = \text{Price Component (rp)} + \text{Quantity Component (rq)}$$

$$0\% \leq R\% \leq 40\%$$

#### PRICE COMPONENT ( $r_p$ )

Par Price (\$/m <sup>3</sup> )	$r_p$
$PP \leq 250.0$	$(PP - 190.0) \times (0.0006) \times 100$
$250.0 < PP \leq 400.0$	$[(PP - 250.0) \times 0.0010] + 0.0360 \times 100$
$400.0 < PP \leq 535.0$	$[(PP - 400.0) \times 0.0005] + 0.1860 \times 100$
$PP > 535.0$	$[(PP - 535.0) \times 0.0003] + 0.2535 \times 100$

$R_p$  can be negative, and has a 35% maximum.

The par price is set monthly and is equal to the average wellhead price.

#### QUANTITY COMPONENT ( $r_q$ )

Quantity (m <sup>3</sup> /month)	$r_q$
$Q \leq 106.4$	$[(Q - 106.4) \times 0.0026] \times 100$
$106.4 < Q \leq 197.6$	$[(Q - 106.4) \times 0.0010] \times 100$
$197.6 < Q \leq 304.0$	$[(Q - 197.6) \times 0.0007] + 0.0912 \times 100$
$Q > 304.0$	$[(Q - 304.0) \times 0.0003] + 0.1657 \times 100$

$R_q$  can be negative and has a 30% maximum.

Q is the monthly production in m<sup>3</sup>.

#### Field Condensate

Field condensate is separated from gas in the field and sold without further processing before entering a gas gathering system. The royalty rate for field condensate is calculated using the oil royalty formula and the following inputs:

- PP is the par price of pentanes-plus.
- Q includes the total monthly production of field condensate and gas from the well event. Gas volume is converted to a condensate equivalent volume as follows:

$$(\text{Gas volume, e}^3\text{m}^3) / 0.78783 = \text{condensate in m}^3$$

#### Royalty Payment

Of the regimes described in this report, Alberta's crude oil royalty regime is the only one that takes royalty in kind. The Alberta Government markets oil delivered as Crown royalty on its behalf.

## ii. ROYALTY ADJUSTMENTS

### New Well Royalty Rate

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Refer to Alberta Energy Information Letter 2009-23.

New oil wells and some wells recommencing production are subject to a maximum 5% royalty rate for all products. This royalty rate applies for 12 production months, subject to a 50,000 barrel of oil equivalent production cap.

### Qualifying Wells

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The well must be spud on or after April 1, 2009.

- The well must be classified as an oil, gas or crude bitumen well when it commences or recommences production.
- Must be subject to the payment of royalty under the Petroleum Royalty Regulation, 2009, the Natural Gas Royalty Regulation, 2009 or section 27 of the Oil Sands Royalty Regulation, 2009.
- A well recommencing production on or after April 1, 2011 can qualify if it did not produce crude oil or gas (other than excluded production) in the 36 months prior to commencing production.
- A well recommencing production on or after April 1, 2011 can also qualify if it did not produce crude oil or gas (other than excluded production) from January 1, 2009 to March 31, 2011, and average monthly production is less than 100 m<sup>3</sup> for:
  - all producing months in the January 1, 2007 to December 31, 2008 period if the well produced for three months or less during that period, or
  - the last three producing months in that period if the well was on production for more than three months.

## iii. OIL ROYALTY PROGRAMS

### 1. Deep Oil Exploration Well Program

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Refer to Alberta Energy Information Letter 2009-03.

This program provides a royalty holiday of up to \$1,000,000 per well. Royalty is not payable on oil produced from an eligible well:

- (a) for the first 12 months that exploratory oil is obtained from the oil well event or oil sands well event,
- (b) until the cumulative value of the royalty on the exploratory oil that would be payable in the absence of this Regulation equals \$1,000,000 multiplied by the Crown interest in the exploratory oil,
- (c) 5 years from the finished drilling date if the finished drilling date is on or before December 31, 2013, or
- (d) until December 31, 2018, whichever occurs first.

### Qualifying Wells

To qualify, a well must have a true vertical depth of more than 2,000 metres, and be classified by the ERCB as a New Field Wildcat (NFW), New Pool Wildcat (NPW) or in the case of a deepened well, a Deeper Pool Test (DPT).

### 2. Transitional Royalty Rates

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Refer to “Gas Programs” for a description of the oil and gas transitional royalty framework. Transitional oil wells are subject to a revised royalty formula with a 50% maximum rate. Effective January 1, 2011, no new wells will be eligible for transition rates.

$R\% = \text{Price Component } (r_p) + \text{Quantity Component } (r_q)$

$0\% \leq R\% \leq 50\%$

### PRICE COMPONENT ( $r_p$ )

Par Price (\$/m <sup>3</sup> )	$r_p$
$PP \leq 250.0$	$(PP - 210.0) \times (0.00035) \times 100$
$250.0 < PP \leq 350.0$	$[(PP - 250.0) \times 0.0001] + 0.0140] \times 100$
$PP > 350.0$	$[(PP - 350.0) \times 0.00005] + 0.24] \times 100$

$R_p$  can be negative, and has a 35% maximum.

The par price (PP) is set monthly and is equal to the average wellhead price.

### QUANTITY COMPONENT ( $r_q$ )

Quantity (m <sup>3</sup> /month)	$r_q$
$Q \leq 30.4$	$[(Q - 30.4) \times 0.0013] \times 100$
$30.4 < Q \leq 152.0$	$[(Q - 30.4) \times 0.0013] \times 100$
$152.0 < Q \leq 273.6$	$[(Q - 152.0) \times 0.0008] + 0.1581] \times 100$
$Q > 273.6$	$[(Q - 273.6) \times 0.0002] + 0.2554] \times 100$

$R_q$  can be negative and has a 35% maximum.

Q is the monthly production in m<sup>3</sup>.

### 3. Shale Gas New Well Royalty Rate

An oil well that starts producing on or after May 1, 2010 exclusively from shale formations may qualify based on an application to the Department of Energy for a maximum 5% royalty rate on all products

### 4. Horizontal Oil Royalty Rate

Refer to Alberta Energy Information Letter 2009-23.

Horizontal oil wells spud on or after May 2010 are subject to a maximum 5% royalty rate for all products. Volume and product limits are set according to the depth of the well.

Measured Depth (metres)	Maximum eligibility (months)	Volume cap Barrels of oil equivalent
Less than 2,500	18	50,000
2,500 up to 3,000	24	60,000
3,000 up to 3,500	30	70,000
3,500 up to 4,000	36	80,000
4,000 up to 4,500	42	90,000
More than 4,500	48	100,000

### 5. 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
- Consumed Energy
- Injectant
- Breakthrough Processing Allowance
- Transportation
- Overhead Allowance

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

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

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 ERCB. The key criteria for scheme approval are:

1. The scheme must receive technical approval from the ERCB 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.

## 6. 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 Programs” for a description of program benefits and eligibility criteria.

## C. 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 for a single, generic royalty regime established through legislation rather than individual Crown agreements. Such an approach would place all new projects on a level playing field, create fiscal certainty and stability, and encourage oil sands investment.



The Government of Alberta accepted that recommendation and began work to develop 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.

A decade later, after considering the recommendations of the Royalty Review Panel's report (released in September 2007) and further consultations with stakeholders, the Government drafted significant amendments to the generic oil sands royalty regime. These changes came into effect on January 1, 2009 after the enactment of the *Oil Sands Royalty Regulation, 2009* (AR 223/08).

### Objectives

Alberta's generic oil sands royalty regime aims to provide 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 arrangements 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 provides the basis for the regulations establishing the generic oil sands royalty regime.

The *Oil Sands Royalty Regulation, 2009*(AR223/08) came into effect on January 1, 2009. It sets out the main administrative provisions of the oil sands royalty regime, including:

- requirements for oil sands royalty project approval;
- treatment of project costs and revenues;
- royalty calculation;
- royalty reporting and payment mechanisms.

Two accompanying Ministerial regulations complement the *Oil Sands Royalty Regulation, 2009*. The *Oil Sands Allowed Costs (Ministerial) Regulation* (AR231/2008) provides detailed information on the definition, valuation and allocation of allowed costs, and the calculation of return allowance. The *Bitumen Valuation Methodology (Ministerial) Regulation* (AR 232/2008) provides a generic methodology to value project bitumen for royalty purposes, where a project has insufficient arm's length sales to generate a fair market valuation.

### Key Features of the Oil Sands Royalty Regulation, 2009

#### 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 ERCB, they can apply to the Department for royalty project status under the Oil Sands Royalty Regulation, 2009. Approval as an oil sands royalty project is by Ministerial Order.

The Minister must be satisfied, before issuing an oil sands project (or project amendment) approval order, that the project is an appropriately defined entity for royalty purposes. In making this determination he must 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, and meet the specified project use threshold;
- Whether the project and **all its components** are **economically justifiable** and function as an integrated **economic unit**; and
- The project approval's impact **on 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.

Well-based oil sands recovery schemes that do not apply for royalty project status under the generic regime, or are not approved as projects, pay cash royalties based on the conventional oil royalty regime. Any recovery of oil sands from mining projects without royalty project status pays a royalty of 20% of production, valued at a prescribed par price.

#### **Royalty:**

The Regulation establishes a royalty regime based on a “net revenue royalty” or “revenue minus cost” approach. Before a project reaches “payout” (i.e. the first time when the developer has recovered all the allowed costs of the project, including a return allowance on those costs equal to the Government of Canada long-term bond rate [“LTBR”]), it pays a low royalty rate based on the gross revenue of the oil sands project. Since January 1, 2009, this gross revenue royalty rate has been indexed to the Canadian dollar price of WTI. The rate is 1% of gross revenue where that price is less than or equal to \$55/bbl, and increases linearly to a maximum of 9% when the WTI price reaches \$120/ bbl.

In determining payout, allowed costs incurred up to three years (up to five years in some specific cases) prior to the approved effective date of the project (the project’s “prior net cumulative balance”) are included as part of recoverable costs for the project owner.

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

$$\text{Unit Price}^* = (\text{TC} - \text{HC}) / \text{TD}$$

#### **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.

\*If a project does not have sufficient arm’s length sales to establish a fair market value for its product(s), this formula is modified.

Revenue generated from sources other than the sales of oil sands products is called “other net proceeds” and is treated as a deduction from allowed costs rather than being included in project revenue.

After an oil sands royalty project reaches payout, the royalty payable to the Crown is equal to the greater of:

- (a) the gross revenue royalty (1% - 9%) for the period, and
- (b) the royalty percentage (25% - 40%) of net revenue for the period.

Effective January 1, 2009 the royalty percentage of net revenue is also indexed to the Canadian dollar price of WTI. It is 25% when the WTI price is less than or equal to \$55/bbl, rising linearly to a maximum of 40% when the price reaches \$120/bbl.

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

**Allowed Costs:**

To be an allowed cost of a project for royalty purposes, a cost must be:

- incurred by or on behalf of the Project lessee or operator.
- incurred to carry out project operations.
- reasonable under the circumstances in which it occurred.
- adequately evidenced and supported.

Fundamental costs of a project are those incurred directly to:

- recover, obtain, process, transport, or market oil sands products recovered from the Project;
- reclaim or abandon Project lands;
- comply with applicable environmental laws.

Fundamental costs, and the “specifically included” costs listed in the Schedule of the *Oil Sands Allowed Cost (Ministerial) Regulation*, are allowed costs of a Project. A Project operator may apply to the Minister for the approval of other “discretionary” allowed costs. These may be approved if they directly and materially benefit Project operations.

All allowed costs (operating and capital) of a Project are 100% credited to the project in the year in which they are incurred. After a project reaches payout, a loss incurred in any period (and an appropriate return allowance) is carried forward as an allowed cost in the next period.

**Reporting and Payment Mechanisms:**

The *Oil Sands Royalty Regulation, 2009* prescribes the royalty payment and reporting requirements of approved projects. Pre-payout projects pay royalty on a monthly basis. Post-payout projects pay royalty on a periodic basis (generally annual). However, they are required to pay monthly royalty installments based on a good faith estimate of their period operations.

While the reporting format differs between pre- and post-payout projects, both types are required to submit monthly and annual reports, as well as annual operator forecasts of future operations and 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 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 allowed for each title owner.

$$\text{FMT} = \text{FGF} + \text{GWCF}$$

#### Natural Gas

$$\text{FGF} = R \times M \times V \times T \text{ when ADP} > 16.9 \text{ } 10^3\text{m}^3/\text{day}$$

$$\text{FGF} = M \times V \times A \times T \text{ when ADP} < 16.9 \text{ } 10^3\text{m}^3/\text{day}$$

#### Where:

ADP = Average daily production

R = Prescribed tax rate = 0.069

V = Value (\$/10<sup>3</sup>m<sup>3</sup>)

M = Annual field gas production (10<sup>3</sup>m<sup>3</sup>/year)

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

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

#### Condensate

$$\text{GWCF} = R \times M \times V \times T$$

#### Where:

R = Prescribed tax rate = 0.269

M = (0.0833 x Q<sup>2</sup> / 105.94 when Q < 2,288.4 m<sup>3</sup>/year

M = (Q / 4) - 228.84 when Q > 2,288.4 m<sup>3</sup>/year

Q = Production (m<sup>3</sup>/year)

V = Price (\$/m<sup>3</sup>)

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 tax reductions for low productivity wells. In addition, there is an annual tax exemption of \$1,600 for gas and/or oil allowed for each title owner.

$$\text{FMT} = \text{COF} + \text{SGF}$$

#### Crude Oil

$$\text{COF} = R \times M \times V \times T$$

#### Where:

R = Prescribed tax rate = 0.269

M = (0.0833 x Q<sup>2</sup> / 105.94 when Q < 2,288.4 m<sup>3</sup>/year

M = (Q / 4) - 228.4 when Q ≥ 2,288.4 m<sup>3</sup>/year

Q = Production (m<sup>3</sup>/year)

V = Price (\$/m<sup>3</sup>)

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

**Solution Gas**

$$SGF = R \times M \times V \times T$$

**Where:**

R = Prescribed tax rate = 0.069

M = Annual solution gas production ( $10^3\text{m}^3/\text{year}$ )

V = Price ( $\$/10^3\text{m}^3$ )

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)

Alberta Allocation Factor =  $\frac{\text{Taxable income in Alberta}}{\text{Taxable income in Canada}}$

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.

## V SASKATCHEWAN

### 1. Royalties

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

<http://www.er.gov.sk.ca/royaltytaxinfocirc>

#### A. Natural Gas

##### Overview

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- 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  $\$/10^3\text{m}^3$ , 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 ( $\$/10^3\text{m}^3$ ) 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

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- 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 3500 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

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- 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, providing 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

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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<sup>3</sup>m<sup>3</sup>/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<sup>3</sup>m<sup>3</sup>/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<sup>3</sup>m<sup>3</sup>/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<sup>3</sup>m<sup>3</sup>/month.
- The fourth tier royalty rate is 0%, if the monthly gas production rate from a gas well is less than 25 10<sup>3</sup>m<sup>3</sup>/month or if the monthly gas production rate from an oil well is less than 64.7 10<sup>3</sup>m<sup>3</sup>/month.

#### i. GAS ROYALTY FORMULAS AND RATES

Old, New and Third Tier Gas

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

$$R\% = (K_g - (X_g / \text{MPG})) - \text{SRC} \text{ when } \text{MGP} > 115.4 \text{ } 10^3\text{m}^3/\text{month}$$

#### Fourth Tier Gas from Gas Wells

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

$$R\% = (C_g \times \text{MGP}) - D_g \text{ when } 25 < \text{MGP} \leq 115.4 \text{ } 10^3\text{m}^3/\text{month}$$

$$R\% = (K_g - (X_g / \text{MPG})) \text{ when } \text{MGP} > 115.4 \text{ } 10^3\text{m}^3/\text{month}$$

#### Fourth Tier Gas from Oil Wells

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

$$R\% = (K_g - (X_g / \text{MPG})) \text{ when } \text{MGP} > 64.7 \text{ } 10^3\text{m}^3/\text{month}$$

#### Where:

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

MGP = Monthly Gas Production (10<sup>3</sup>m<sup>3</sup>/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.

K<sub>g</sub>, X<sub>g</sub>, C<sub>g</sub> and D<sub>g</sub> are constants derived from the following formulas:

#### Old Gas

$$K_g = 26 + (32.5 \times (\text{PGP} - 35) / \text{PGP})$$

$$X_g = K_g \times 57.69$$

$$C_g = K_g / 230.76$$

#### New Gas

$$K_g = 19.5 + (26 \times (\text{PGP} - 35) / \text{PGP})$$

$$X_g = K_g \times 57.69$$

$$C_g = K_g / 230.76$$

**Third Tier Gas**

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

$$X_g = K_g \times 57.69$$

$$C_g = K_g / 230.76$$

**Fourth Tier Gas from Gas Wells**

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

$$X_g = K_g \times 64.7$$

$$C_g = K_g / 205.76$$

$$D_g = K_g / 8.23$$

**Fourth Tier Gas from Oil Wells**

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

$$X_g = K_g \times 64.7$$

**Where:**

PGP is the Provincial average fieldgate price (\$/10<sup>3</sup>m<sup>3</sup>) set for each month, to a minimum of \$35/10<sup>3</sup>m<sup>3</sup> for new and old gas, and \$50/10<sup>3</sup>m<sup>3</sup> for third tier and fourth tier gas. The price is determined prior to the deduction of gas cost allowance.

The current and historical PGP can be found at the following website:

<http://www.er.gov.sk.ca/royaltytaxfactors>

**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****Exploratory Drilling Incentive**

Refer to Information Circular PR-IC04.

The first 25 million m<sup>3</sup> of natural gas produced from a qualifying 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.

**Horizontal Drilling Incentive**

Refer to Information Circular PR-IC14.

The first 25 million m<sup>3</sup> of natural gas produced from a horizontal natural gas well drilled on or after June 1, 2010 and before April 1, 2013 is subject to a maximum royalty rate of 2.5%.



## 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<sup>3</sup>, 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 January 1, 1994 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
<b>Heavy Oil</b>				
<b>New Oil</b>	10%	\$50/m <sup>3</sup>	25%	100 m <sup>3</sup> /month
<b>Third Tier Oil</b>	10%	\$100/m <sup>3</sup>	25%	100 m <sup>3</sup> /month
<b>Fourth Tier Oil</b>	5%	\$100/m <sup>3</sup>	30%	250 m <sup>3</sup> /month
<b>Southwest Designated</b>				
<b>New Oil</b>	12.5%	\$50/m <sup>3</sup>	35%	100 m <sup>3</sup> /month
<b>Third Tier Oil</b>	12.5%	\$100/m <sup>3</sup>	35%	100 m <sup>3</sup> /month
<b>Fourth Tier Oil</b>	5%	\$100/m <sup>3</sup>	30%	250 m <sup>3</sup> /month
<b>Non-Heavy Oil</b>				
<b>Old Oil</b>	20%	\$50/m <sup>3</sup>	45%	100 m <sup>3</sup> /month
<b>New Oil</b>	15%	\$50/m <sup>3</sup>	35%	100 m <sup>3</sup> /month
<b>Third Tier Oil</b>	15%	\$100/m <sup>3</sup>	35%	100 m <sup>3</sup> /month
<b>Fourth Tier Oil</b>	5%	\$100/m <sup>3</sup>	30%	250 m <sup>3</sup> /month

#### i OIL ROYALTY FORMULAS AND RATES

##### Old, New and Third Tier Oil

$$R\% = (K - (X / MOP)) - SRC \text{ to a minimum of } 0\%$$

Fourth Tier Oil

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

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

$$R\% = (K - (X / MOP)) \text{ when } MOP > 136.2 \text{ m}^3/\text{month}$$

##### Where:

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

MOP = Monthly Oil Production (m<sup>3</sup>/month).

SRC = Saskatchewan Resource Credit of 2.5% applicable to oil produced from vertical oil and gas wells drilled on or after February 9, 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 SRC 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
<b>Heavy</b>				
<b>New</b>	$13 + 19.5 \times (\text{HOP} - 50) / \text{HOP}$	$K \times 23.08$	-	-
<b>3<sup>rd</sup> Tier</b>	$13 + 19.5 \times (\text{HOP} - 100) / \text{HOP}$	$K \times 23.08$	-	-
<b>4<sup>th</sup> Tier</b>	$7.14 + 35.71 \times (\text{HOP} - 100) / \text{HOP}$	$K \times 75$	$K/247.48$	$K/9.9$
<b>Southwest Designated</b>				
<b>New</b>	$16.25 + 29.25 \times (\text{SOP} - 50) / \text{SOP}$	$K \times 23.08$	-	-
<b>3<sup>rd</sup> Tier</b>	$16.25 + 29.25 \times (\text{SOP} - 100) / \text{SOP}$	$K \times 23.08$	-	-
<b>4<sup>th</sup> Tier</b>	$7.14 + 35.71 \times (\text{SOP} - 100) / \text{SOP}$	$K \times 75$	$K/247.48$	$K/9.9$
<b>Non-heavy</b>				
<b>Old</b>	$26 + 32.5 \times (\text{NOP} - 50) / \text{NOP}$	$K \times 23.08$	-	-
<b>New</b>	$19.5 + 26 \times (\text{NOP} - 50) / \text{NOP}$	$K \times 23.08$	-	-
<b>3<sup>rd</sup> Tier</b>	$19.5 + 26 \times (\text{NOP} - 100) / \text{NOP}$	$K \times 23.08$	-	-
<b>4<sup>th</sup> Tier</b>	$7.14 + 35.71 \times (\text{NOP} - 100) / \text{NOP}$	$K \times 75$	$K/247.48$	$K/9.9$

**Where:**

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

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

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

Current and historical reference prices can be found at the following website:

<http://www.er.gov.sk.ca/royaltytaxfactors>

### 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 on a fixed volume of oil produced from the well. Until the volume is produced, production from the qualifying well is subject to a maximum royalty rate of 2.5%.

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 <sup>3</sup>
Deep Vertical Development Well	8,000 m <sup>3</sup>
Deep Vertical Exploratory Well	16,000 m <sup>3</sup>

**Where:**

<b>Deep</b>	=	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.
<b>Non-Deep</b>	=	Any well other than a deep well.
<b>Exploratory</b>	=	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.
<b>Development</b>	=	Any well other than an exploratory well.

## 2. Horizontal Well Drilling Incentives

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Refer to Information Circular PR-IC05.

All horizontal oil wells drilled on or after October 1, 2002 qualify for a reduced royalty rate on a fixed volume of oil produced from the well. Until the volume is produced, production from the qualifying well is subject to a maximum royalty rate of 2.5%.

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 <sup>3</sup>
Deep Horizontal Oil Well	16,000 m <sup>3</sup>

**Where:**

<b>Deep</b>	=	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.
<b>Non-Deep</b>	=	Any horizontal well other than a deep horizontal well.

## 3. Other Royalty Programs

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### 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.

#### 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

### A. Natural Gas Freehold Production Tax

#### Overview

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- The freehold production tax structure is similar in concept to the Crown royalty structure. Like the 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.

<b>PTF</b>	=	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

##### Exploratory Drilling Incentive

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Refer to Information Circular PR-IC04.

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<sup>3</sup> of natural gas produced from a qualifying 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.

##### Horizontal Drilling Incentive

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Refer to Information Circular PR-IC14.

All horizontal gas wells drilled on or after June 1, 2010 and before April 1, 2013 qualify for a reduced freehold production tax of 0% on the first 25 million m<sup>3</sup> of natural gas produced.

## B. Oil Freehold Production Tax

### Overview

- The freehold production tax structure is similar in concept to the Crown royalty structure. Like the 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 well-head 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.

### **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:

	<b>Projects Commencing Before April 1, 2005</b>	<b>Projects Commencing On or After April 1, 2005</b>
<b>Before Payout</b>	0%	0%
<b>After Payout</b>	(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**

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The current corporate income tax rate is 12% of taxable income earned in Saskatchewan less the royalty tax rebate. The small business rate is 4.5%.

### **Corporation Capital Tax Resource Surcharge**

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The Corporation Capital Tax Resource Surcharge (CCTRS) 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 CCTRS, 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 1.7% 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%.

## VI MANITOBA

### 1. Royalties

#### A. Natural Gas

##### i. GAS ROYALTY FORMULAS AND RATES

###### Natural Gas

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R% = Royalty rate

R% = 12.5% of monthly sales

###### Low Productivity Wells

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There is no special allowance for low productivity wells.

###### Natural Gas Liquids

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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<sup>3</sup>/month. For well production rates between 50 m<sup>3</sup>/month and 300 m<sup>3</sup>/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<sup>3</sup>/month. For well production rates between 50 m<sup>3</sup>/month and 300 m<sup>3</sup>/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<sup>3</sup>/month. For well production rates between 50 m<sup>3</sup>/month and 300 m<sup>3</sup>/month, a rate between 8.9% and 19.1% is applied.

##### i. OIL ROYALTY FORMULAS AND RATES

R% = Royalty rate

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

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

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

##### Where:

RV = Crown royalty volume

P = Production (m<sup>3</sup>/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<sup>3</sup>/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, 2009 to January 1, 2014)

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<sup>3</sup> or 10 years of production, whichever occurs first. The minimum holiday volume is 500 m<sup>3</sup>. No application is required.

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

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

If  $D > 2$  kilometres:  $HOV = A' \times D2 + B'$

#### Where:

HOV = The holiday oil volume in m<sup>3</sup> 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 =  $1.7 \times P + 230$

B =  $3130 - 13.6 \times P$

A' =  $0.17 \times P + 106.9$

B' =  $3163 - 10.9 \times P$

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

#### Deep Well Holiday Oil Volume (January 1, 2009 to January 1, 2014)

Any new well drilled on or after January 1, 2009 and prior to January 1, 2014, to a depth to fully penetrate the Devonian Duperow Formation, is provided with a holiday volume of 20,000 m<sup>3</sup>. 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 than the Devonian Three Forks Formation, to a maximum of 10,000 m<sup>3</sup>.

#### **Injection Well Holiday (January 1, 2009 to January 1, 2014)**

Wells eligible for the IWI include those drilled for the purpose of injection in an approved enhanced recovery project, as well as vertical or horizontal wells that are converted to injection.

The IWI exemption is for one year beginning in the month in which injection commenced and applies for a vertical well, to the unit tract in which the well is located; and for a horizontal well, to the four unit tracts containing the majority of the injection area, as determined by the director.

Under the IWI, the licensee of a well converted to injection on or after January 1, 2009 may make a one-time request to use any remaining, unproduced holiday oil volume earned by the well under the Manitoba Drilling Incentive Program to extend the exemption period from 12 months to a maximum of 18 months in accordance with the following formula:

$$EP = \frac{UHV}{P Av}$$

#### **Where:**

EP = extension period in number of months, rounded down to the nearest month

UHV = unused holiday volume prior to conversion of well to injection

P Av = average well production over the last 3 production months prior to conversion of well to injection

#### **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<sup>3</sup> holiday oil volume.

## **2. Horizontal Well Royalty Programs**

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#### **Horizontal Well: Holiday Oil Volume (January 1, 2009 to January 1, 2014)**

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, 2009 and prior to January 1, 2014, earns a holiday volume of 10,000 m<sup>3</sup>. The first horizontal leg drilled from a horizontal well on or after January 1, 2009 and prior to January 1, 2014 earns a holiday volume of 3,000 m<sup>3</sup>. 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**

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#### **Marginal Well Major Workover Holiday Oil Volume (January 1, 2009 to January 1, 2014)**

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<sup>3</sup>. 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<sup>3</sup> 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<sup>3</sup>) = Incremental EOR recoverable reserves that are attributed to the approved EOR project.

TRES (m<sup>3</sup>) = 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.

$$\text{TTEP} = (\text{TTEF}) \times (\text{Project Old Oil Production} + \text{Project New Oil Production})$$

**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<sup>1</sup>

<sup>1</sup> 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

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

### B. Oil

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<sup>3</sup>/month)

**Old Oil**

$$\begin{aligned} \text{TR} &= 0 \text{ when } P < 20 \\ &= [(0.43 \times P) - 8.24] \text{ when } 20 < P < 65 \\ &= [42.76 - (1,500 / P)] \text{ when } P > 65 \end{aligned}$$

**New Oil**

$$\begin{aligned} \text{TR} &= 0 \text{ when } P < 36 \\ &= [(0.23 \times P) - 8.11] \text{ when } 36 < P < 65 \\ &= [19.59 - (820 / P)] \text{ when } P > 65 \end{aligned}$$

**Third Tier Oil**

$$\begin{aligned} \text{TR} &= 0 \text{ when } P < 46 \\ &= 11 - (465 / P) \text{ when } P > 46 \end{aligned}$$

**Holiday Oil**

$$\text{TR} = 0 \text{ for all volumes}$$

### 3. Corporate Income Taxes

**Corporate Tax**

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The current corporate income tax rate is 12% of taxable income earned in Manitoba. The small business rate is 5%.

**Royalty Tax Credits and Workover Incentives**

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

## VII YUKON

### Regulations

Yukon's *Oil and Gas Royalty Regulations* were passed in February 2008 authorizing the Government of Yukon to collect royalty for oil and gas recovered on crown lands.

The Yukon royalty system is based on an ad valorem structure with the primary objectives being transparency and administrative simplicity for both government and industry.

### Royalty Calculation for Crude Oil, Gas and Field Condensate

The basic formulas for calculating royalty for crude oil, gas and field condensate are similar and are described in their respective sections of the regulations.

$$R\% = \frac{10 \cdot SP + 30(PP - SP)}{PP}$$

R = Royalty rate

SP = Select Price

PP = Par Price (Reference Price)

There is an initial period during which the royalty rate for crude oil and gas production is reduced to 2.5% for each well, subject to production thresholds.

### Prescribed Prices and Allowances

Prices and royalty allowances are prescribed by the Oil and Gas Resources Division Head. Select Prices are set from time to time while Par and Reference Prices are set for each production month in which there is production. For the present, the Division Head has set Par and Reference Prices at the same value. The Division Head also prescribes royalty allowances that are deducted from royalty payable. The royalty allowances are proxies in lieu of transportation and processing costs. Prescribed prices and allowances are posted on the Oil and Gas Resources website.

### Royalty Client

A royalty client, as defined in the regulations, is a Yukon disposition holder. Royalty clients are responsible for the payment of royalty proportionate to the holder's specified undivided interest in the disposition.

Royalty clients are required to submit a royalty return for each month in which there is production. Royalty must be paid by the last day of the month following the production month being reported.

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

## VIII 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.



## IX 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.

**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*.

The federal government administers federal Crown lands (frontier lands) in the Northwest Territories, Nunavut and the northern offshore. Frontier lands do not include subsurface land title which is held by Aboriginal groups pursuant to land claim agreements. The Minister of Aboriginal Affairs and Northern Development manages oil and gas rights on federal lands North of 60 degrees, and the National Energy Board has the authority to award licenses to companies who wish to explore or produce gas.

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.

### 2. Frontier Lands

#### A. Natural Gas

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

**Net profit is calculated as:**

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

Operating and capital costs receive 10% and 1% uplifts respectively 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 paid and a return allowance. Payout is calculated on a working interest basis, by project.

The Investment Royalty Credit was phased out in 2008 when amendments were made to the FLPRR, though companies may continue to claim.

### 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 Investment Royalty Credit was phased out in 2008 when amendments were made to the FLPRR, though companies may continue to claim expenses incurred while the program was in effect.

Introduced in the 2008 amendments was an opportunity for companies to defer royalties by investing in a certified Abandonment and Restoration Royalty Trust Account.

## B. Oil

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

## 3. Corporate Income Taxes

### Tax Rates

The general federal tax rate is 16.5% for 2011 and 15% for 2012 and subsequent years. The corporate surtax for all corporations was eliminated in 2008 and the capital tax was eliminated in 2006.

### Allowable Deductions

Corporations are generally allowed deductions for amounts paid out to earn income, including operating expenses, capital cost allowance, interest expense, resource expenses, and general and administrative expenses. Crown royalties have been generally deductible against income since 2007. Provincial taxes are not deductible.

Capital cost allowance provides a deduction for tangible capital investment. Many classes of depreciable property exist, the most frequent being Class 41 for oil and gas equipment, which provides a 25% write-off rate on a declining balance basis. Other property classes relevant to the oil and gas sector are discussed in Canada Revenue Agency's Income Tax Interpretation Bulletin number IT-476R.

<http://www.cra-arc.gc.ca/E/pub/tp/it476r/it-476r-e.pdf>

Resource expenses are grouped into one of three pools, which can be carried forward indefinitely:

- Canadian Exploration Expense (CEE) generally includes certain intangible costs incurred to determine the “existence, location, extent or quality” of a crude oil or natural gas reservoir not previously known to exist. CEE can generally be deducted against income at up to 100% of the balance;
- Canadian Development Expense (CDE) generally includes the costs (to the extent such costs are not CEE) of drilling, converting or completing a well, building a temporary access road or preparing a site. CDE can be deducted at up to 30% per year on a declining balance basis; and
- Canadian Oil and Gas Property Expense (COGPE), generally includes the cost of acquiring rights to explore for, drill or extract oil or natural gas, or to acquire an oil or natural gas well or other resource property. COGPE can be deducted at up to 10% per year on a declining balance basis.

### Small Business Deduction

A reduced tax rate of 11% applies on the first \$500,000 of qualifying income of small Canadian-controlled private corporations (CCPCs). The reduced rate is phased out for CCPCs with taxable capital between \$10 million and \$15 million. The 11% rate has been applicable since 2008 and the \$500,000 limit has been applicable since 2009.

## X 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.

For each commodity group (natural gas, non heavy oil, and heavy oil) the following graphs are presented:

**New wells:** This graph depicts the royalty rates in effect for new well development (after expiration of applicable royalty adjustments and programs).

**Prior wells:** This graph depicts royalty rates in effect for prior well vintages.

Note that the Alberta royalty curves are not date sensitive, so are included in each graph.

### Natural Gas

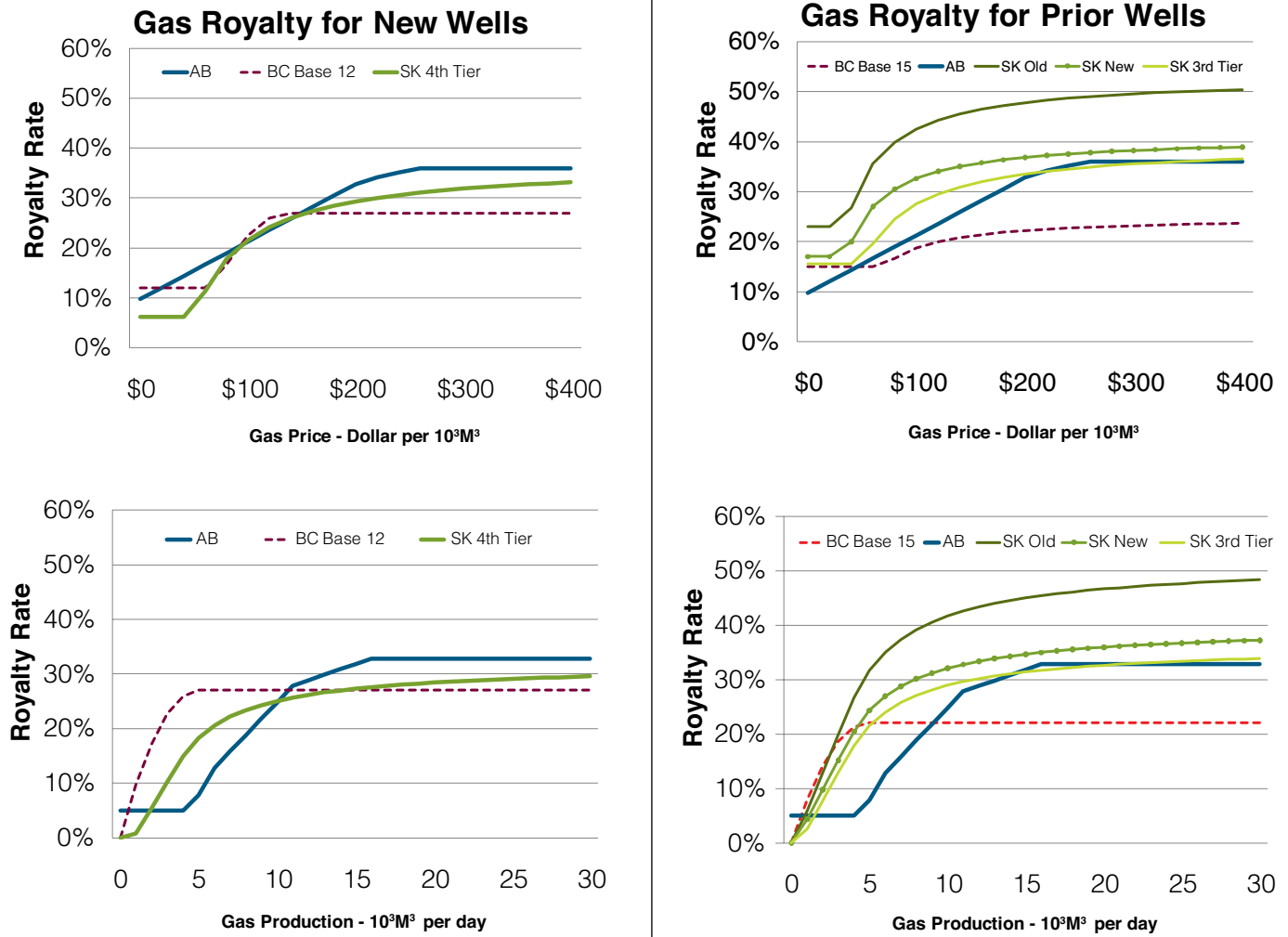
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In the graphs depicting price, the well production rate is assumed to be  $25 \times 10^3 \text{m}^3$  per day. In the graphs depicting production, price is assumed to be \$200 per  $10^3 \text{m}^3$ .

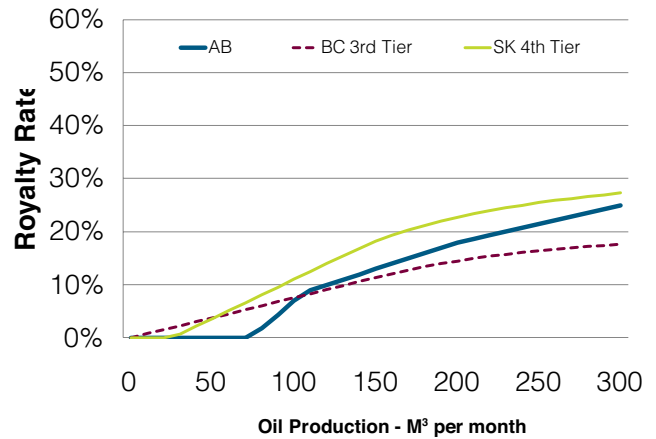
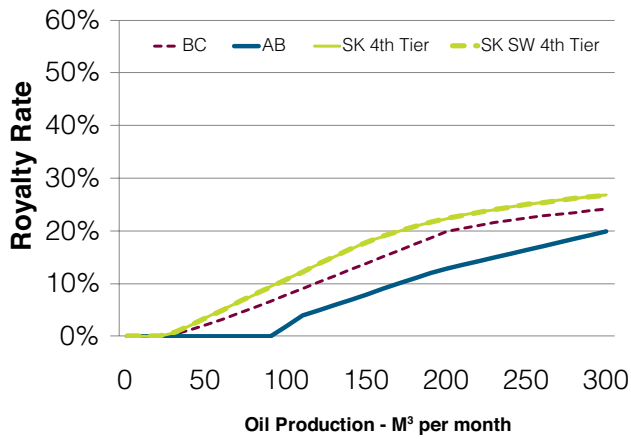
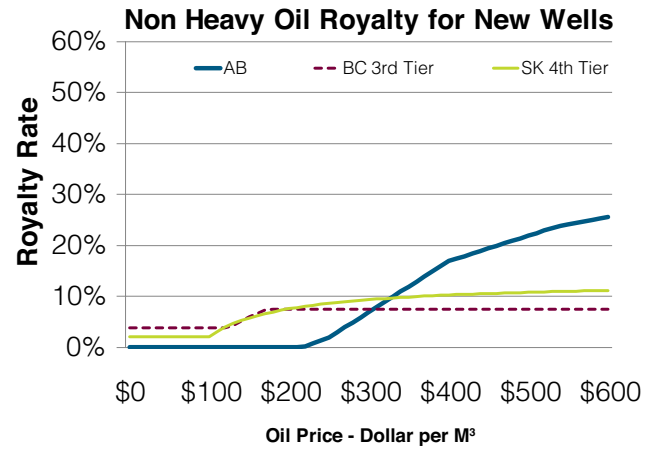
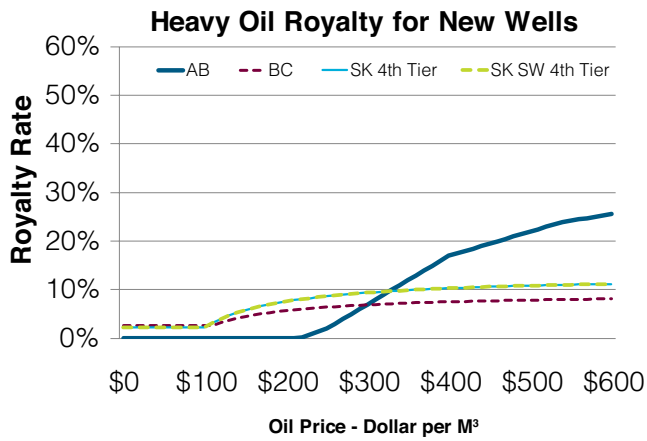
### Crude Oil

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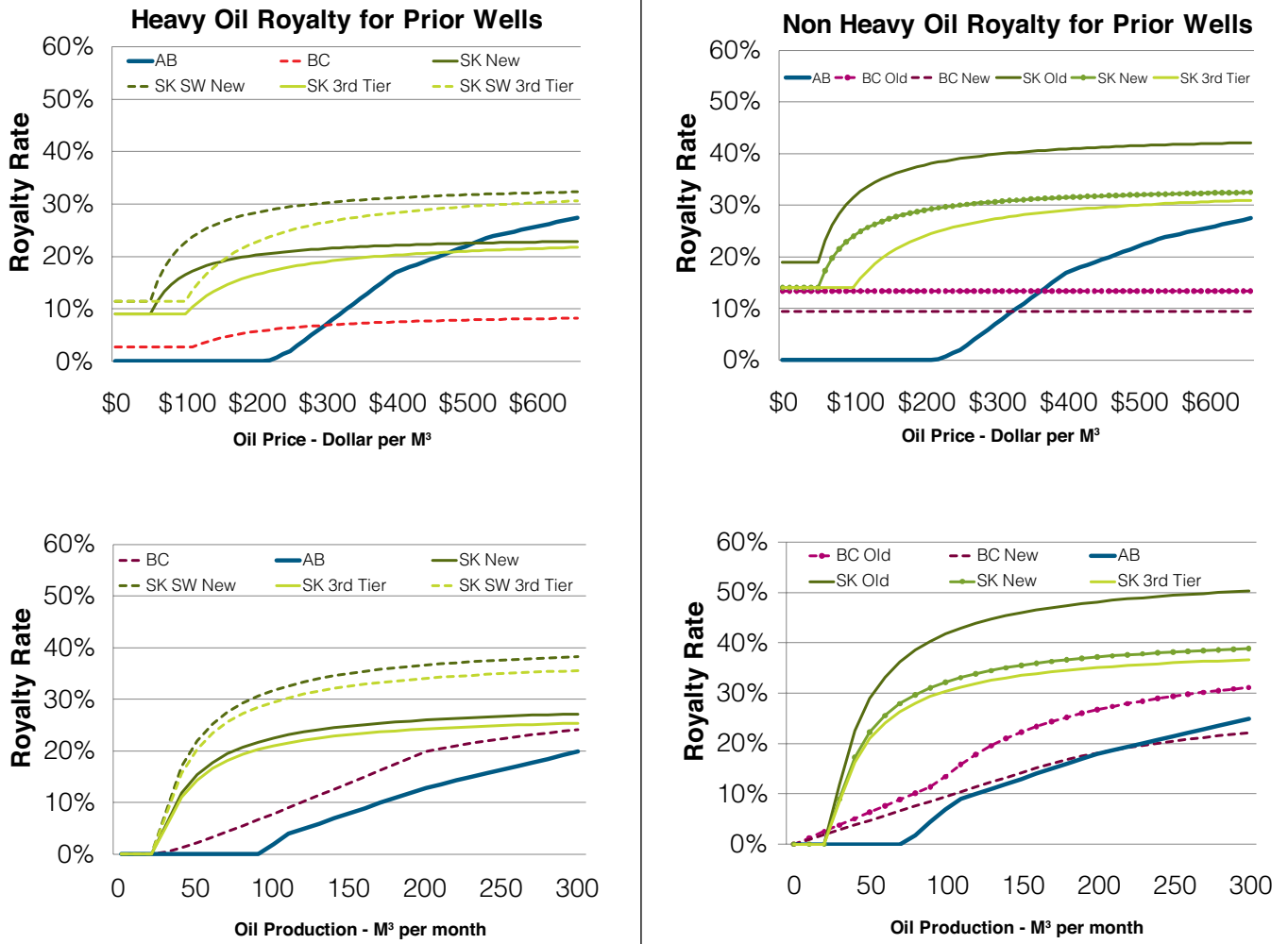
In the graphs depicting price, both heavy oil and non-heavy oil have an assumed production rate of  $100 \text{m}^3$  per month. In the graphs depicting production, heavy oil has a fixed price of  $\$500/\text{m}^3$ , while non-heavy oil has a fixed price of  $\$550/\text{m}^3$ .



**Figure 1:** Gas royalty rates are a function of well productivity 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 2:** Oil royalty rates for new wells are a function of wellhead productivity and price. British Columbia and Saskatchewan royalty rates are also sensitive to density (Saskatchewan has separate categories for heavy oil under fourth tier oil: heavy oil and southwest designated oil).



**Figure 3:** Oil royalty rates are a function of wellhead productivity (with the exception of British Columbia non heavy oil, royalty rates are also price sensitive). British Columbia and Saskatchewan oil royalty is sensitive to density (Saskatchewan has separate categories for heavy oil under new oil and third tier oil: heavy oil and southwest designated oil).

## XI CONTACTS

### British Columbia

#### Ministry of Energy

Website: [www.empr.gov.bc.ca](http://www.empr.gov.bc.ca)

#### Ministry Office

General information about the Ministry  
PO Box 9318, Stn Prov Govt,  
1810 Blanshard St.,  
Victoria BC V8W 9N3  
Phone: (250) 952-0241

#### Oil and Gas Division

Oil and gas policy and information  
PO Box 9323, Stn Prov Govt,  
1810 Blanshard St.,  
Victoria BC V8W 9N3  
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#### Ministry of Finance

Mineral, Oil & Gas Revenue Branch  
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VICTORIA BC V8W 9N3  
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#### Queen's Printer

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Visit the Queen's Printer website at:  
<http://www.bcsolutions.gov.bc.ca/qp/>  
563 Superior Street  
PO Box 9452 Stn Prov Govt  
Victoria BC V8W 9V7  
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### Alberta

#### Alberta Department of Energy

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#### Edmonton Library:

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#### Oil Royalty Operations

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#### Oil Sands Operations

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#### Tenure Business Unit

##### Continuations, Petroleum and Natural Gas Sales and Registrations

Fax: (780) 422-1123

Crown equity and Freehold Mineral Tax  
Fax: (780) 422-0382

#### Alberta Queen's Printer

Website: [www.qp.gov.ab.ca](http://www.qp.gov.ab.ca)  
5th Floor, Park Plaza  
10611– 98 Avenue  
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#### Alberta Finance & Enterprise Tax & Revenue Administration

Website: [www.finance.gov.ab.ca/](http://www.finance.gov.ab.ca/)  
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Toll Free: 310-0000 then Phone or Fax number  
(in Alberta only)

Visit the following websites for more information about Alberta and its energy and mineral resources:

#### Government of Alberta

Website: [www.gov.ab.ca](http://www.gov.ab.ca)

#### Alberta Energy Resources Conservation Board

Website: [www.ercb.ca](http://www.ercb.ca)

## Saskatchewan

### Saskatchewan Energy and Resources

Website: [www.ir.gov.sk.ca/](http://www.ir.gov.sk.ca/)

#### Head Office

300 - 2103 - 11th Avenue  
Regina Saskatchewan S4P 3Z8  
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#### Resource Development

2101 Scarth Street  
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#### Saskatchewan Queen's Printer

Saskatchewan Statutes and Regulations  
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## Manitoba

### Manitoba Innovation, Energy and Mines

Website: [www.gov.mb.ca/iedm/petroleum](http://www.gov.mb.ca/iedm/petroleum)

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## Federal

### Northern Oil and Gas Branch – Indian and Northern Affairs Canada

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