Oil Sands Royalty Business Overview

Oil Sands Royalty Business Training
Alberta Energy
June 12, 2019
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Topics

• Oil Sands Royalty Regimes
  – Non-Project Well Royalty (NPR)
  – Oil Sands Generic Royalty (OSR)
  – Crown Agreement Royalty (CSR)

• Royalty Reporting

• Other Reporting

• Common Reporting Issues

• Penalties & Interest
Royalty Regimes

• **Non-Project Well Royalty (NPR)**
  • For oil sands wells not in approved OSR Projects
  • Crown share based on the ultra heavy oil royalty rates in the Petroleum Royalty Regulation, 2009 or the Petroleum Royalty Regulation, 2017
  • Pay cash royalty in accordance with terms prescribed in the *Oil Sands Royalty Regulation, 2009 (OSRR’09)*

• **Oil Sands Royalty (OSR)**
  • For approved OSR Projects
  • Pay royalty on gross or net revenue of Project
  • Pay cash royalty in accordance with terms prescribed in the OSRR’09

• **Crown Agreement Royalty (CSR)**
  • For Oil Sands Crown Agreements
  • Pay cash royalty in accordance with terms prescribed in applicable Crown Agreement
Non-Project Well Royalty (NPR)

- All producing wells not in an approved OSR Project are charged Non-Project Royalty (in accordance with calculation methodologies in the *Petroleum Royalty Regulation 2009 & 2017*, as if product was Crude Oil)

- Crown Royalty Share (Royalty Volumes) based on:
  - Production x Crown Interest x R%*
  - *R% based on ultra heavy oil par price and royalty formulas in either *Petroleum Royalty Regulation, 2009* or *Petroleum Royalty Regulation, 2017*

- Converted to cash royalty
  - Royalty Volumes x Unit Value
  - less Transportation Allowances

- Once approved in a Project:
  - NPR royalty will be reversed and OSR royalty will be charged (amended reporting is required) from the effective date of the Project
Alberta Royalty Framework Formulas (ARF)

http://www.energy.alberta.ca/AU/Royalties/Pages/default.aspx

Alberta's Modernized Royalty Framework

This framework came into effect January 1, 2017. The framework was developed based on recommendations from the Alberta Royalty Review Advisory Panel which submitted its Alberta at a Crossroads report on Alberta's royalties to government after a six-month review process. Formulas were finalized on April 21, 2016 and on July 11, 2016, the government announced two new royalty programs.

- Drilling and Completion Cost Allowance (C*) for new wells (2017)
- Drilling and Completion Cost Allowance (C*) for wells re-entered (2017)
- Crude Oil, Pentane Plus, Field Condensate and Bitumen from Non-project wells (2017)
- Natural Gas (Methane) and Ethane (2017)
- Propane (extracted and in stream components) (2017)
- Butane (extracted and in stream components) (2017)
- Frequently Asked Questions for the Modernized Royalty Framework

Strategic Programs under Alberta's Modernized Royalty Framework

- Enhanced Hydrocarbon Recovery Program (2017)
- Emerging Resources Program (2017)
- Technical briefing, Strategic Programs and Early Opt-In (updated December 2016)

You can subscribe for updates to royalty content or if you have technical questions please contact oil.gas.royalty@gov.ab.ca.

Industry Information Sessions

Royalty Formulas, Charts, Tables and Curves for wells spud up to and including December 31, 2016

Alberta Royalty Framework formulas; Oil
Royalty Formulas – Conventional Oil  
Effective January 1, 2011

R% = Price Component (r_p) + Quantity Component (r_q)

AFR (2011): R% has a minimum of 0% and a maximum of 40%
Transition: R% has a minimum of 0% and a maximum of 50%

### Royalty Parameters

<table>
<thead>
<tr>
<th>Royalty Parameters</th>
<th>Price ($/m³)</th>
<th>% Change (%$/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P₁</td>
<td>190.00</td>
<td>210.00</td>
</tr>
<tr>
<td>P₂</td>
<td>250.00</td>
<td>250.00</td>
</tr>
<tr>
<td>P₃</td>
<td>400.00</td>
<td>350.00</td>
</tr>
<tr>
<td>P₄</td>
<td>535.00</td>
<td>--</td>
</tr>
<tr>
<td>Q₁</td>
<td>106.4</td>
<td>30.4</td>
</tr>
<tr>
<td>Q₂</td>
<td>197.6</td>
<td>152.0</td>
</tr>
<tr>
<td>Q₃</td>
<td>304.0</td>
<td>273.6</td>
</tr>
</tbody>
</table>

### Price Component (r_p)

<table>
<thead>
<tr>
<th>Price ($/m³)</th>
<th>r_p</th>
<th>Transition Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>PP ≤ 250.00</td>
<td>(((PP - 190.00) * 0.00006) * 100)</td>
<td>PP ≤ 250.00</td>
</tr>
<tr>
<td>250.00 ≤ PP ≤ 400.00</td>
<td>(((PP - 250.00) * 0.00010) + 0.0360) * 100</td>
<td>250.00 ≤ PP ≤ 350.00</td>
</tr>
<tr>
<td>400.00 ≤ PP ≤ 535.00</td>
<td>(((PP - 400.00) * 0.00005) + 0.1800) * 100</td>
<td>PP ≤ 350.00</td>
</tr>
<tr>
<td>PP &gt; 535.00</td>
<td>(((PP - 535.00) * 0.00003) + 0.2535) * 100</td>
<td>--</td>
</tr>
</tbody>
</table>

Maximum: 35%

Note: r_p can be negative

### Quantity Component (r_q)

<table>
<thead>
<tr>
<th>Quantity (m³/month)</th>
<th>r_q</th>
<th>Transition Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q ≤ 106.4</td>
<td>((Q - 106.4) * 0.00026) * 100</td>
<td>Q ≤ 30.4</td>
</tr>
<tr>
<td>106.4 ≤ Q ≤ 197.6</td>
<td>((Q - 106.4) * 0.00010) * 100</td>
<td>Q ≤ 152.0</td>
</tr>
<tr>
<td>197.6 ≤ Q ≤ 304.0</td>
<td>((Q - 197.6) * 0.00007) * 0.0912 * 100</td>
<td>Q ≤ 273.6</td>
</tr>
<tr>
<td>Q &gt; 304.0</td>
<td>((Q - 304.0) * 0.00003) + 0.1657 * 100</td>
<td>Q &gt; 273.6</td>
</tr>
</tbody>
</table>

Maximum: 30%

Note: r_q can be negative

### Examples

<table>
<thead>
<tr>
<th>Price ($/ms)</th>
<th>Quantity (m³/month)</th>
<th>r_p</th>
<th>r_q</th>
<th>ARF (2011)</th>
<th>R%</th>
<th>Transition Wells</th>
<th>r_p</th>
<th>r_q</th>
<th>R%</th>
</tr>
</thead>
<tbody>
<tr>
<td>400.00</td>
<td>50.0</td>
<td>18.60%</td>
<td>-14.66%</td>
<td>3.94%</td>
<td>2.65%</td>
<td>2.55%</td>
<td>5.20%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>400.00</td>
<td>200.0</td>
<td>18.60%</td>
<td>9.29%</td>
<td>27.89%</td>
<td>2.65%</td>
<td>19.65%</td>
<td>22.30%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>600.00</td>
<td>50.0</td>
<td>27.30%</td>
<td>-14.66%</td>
<td>12.64%</td>
<td>3.63%</td>
<td>2.55%</td>
<td>6.20%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>600.00</td>
<td>200.0</td>
<td>27.30%</td>
<td>9.29%</td>
<td>36.59%</td>
<td>3.63%</td>
<td>19.65%</td>
<td>23.30%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Royalty Share Methodology Under Petroleum Royalty Regulation 2017

Modernized Royalty Framework (MRF)

http://www.energy.alberta.ca/AU/Royalties/Pages/default.aspx

About Royalties

On behalf of Albertans, the Government of Alberta is the owner of 81% of the mineral rights in the province, which includes oil and gas. When companies develop the resources, they must pay the province - that’s called a royalty. As resource owner, the Alberta government sets the terms and conditions for development and the royalty rates.

Albertans can access more information on the new royalty system on the Alberta government’s website. This will help Albertans understand the value received from royalties for crude oil, natural gas and oil sands.

Alberta’s Modernized Royalty Framework

This framework came into effect January 1, 2017. The framework was developed based on recommendations from the Alberta Royalty Review Advisory Panel which submitted its Alberta at a Crossroads report on Alberta’s royalties to government after a six-month review process. Formulas were finalized on April 21, 2016 and on July 11, 2016, the government announced two new royalty programs.

- Alberta’s Modernized Royalty Framework Overview (2017)
- Drilling and Completion Cost Allowance (C*) for new wells (2017)
- Drilling and Completion Cost Allowance (C*) for wells re-entered (2017)
- Crude Oil, Pentane Plus, Field Condensate and Lightight (2017)
- Natural Gas (methane) and Ethane (2017)
- Propane (extracted and in stream components) (2017)
- Butane (extracted and in stream components) (2017)
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- Emerging Resources Program (2017)
- Technical briefing, Strategic Programs and Early Opt-in (2016) (updated December 2016)

You can subscribe for updates to royalty content or if you have technical questions please contact oil.gas.royalty@gov.ab.ca.

Royalty Formulas, Charts, Tables and Curves for wells spud up to and including December 31, 2016

- Alberta Royalty Framework formulas, Oil
Modernized Royalty Framework: Formulas
Conventional Oil, Pentane Plus (extracted and in-stream component) and Field Condensate
For wells spud on or after January 1, 2017

R% = Price Component \( r_p \) + Quantity Adjustment \( r_q \)

R% has a minimum of 5% and maximum of 40%

<table>
<thead>
<tr>
<th>Royalty Parameters</th>
<th>Price (C$/m^3)</th>
<th>% Change (%$/m^3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P1</td>
<td>251.70</td>
<td>0.07100%</td>
</tr>
<tr>
<td>P2</td>
<td>409.02</td>
<td>0.03900%</td>
</tr>
<tr>
<td>P3</td>
<td>723.64</td>
<td>0.02000%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Price Component ( r_p )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Price ($/m^3)</td>
</tr>
<tr>
<td>PP&lt;=251.70</td>
</tr>
<tr>
<td>251.70&lt;PP&lt;=409.02</td>
</tr>
<tr>
<td>409.02&lt;PP&lt;=723.64</td>
</tr>
<tr>
<td>PP&gt;723.64</td>
</tr>
<tr>
<td>Maximum</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Maturity Threshold</th>
<th>Q</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q oil equivalent volumes</td>
<td>194.0 (m^3/e/month)</td>
<td>0.1350% (%/m^3/e/month)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Quantity Adjustment (oil equivalent volume)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quantity (m^3/e/month)</td>
</tr>
<tr>
<td>Q &gt;=194.0</td>
</tr>
<tr>
<td>Q &lt;194.0</td>
</tr>
</tbody>
</table>

Note: Quantity is calculated at a well level, where m^3/e/month = m^3 equivalent per month.

Note: \( r_q \) is 0 or negative

A well will pay 5% royalty rate until revenue equals \( C^*(\$) \). R% applies once a well’s revenues exceed \( C^* \) (post-\( C^* \) phase). The minimum royalty rate in the post-\( C^* \) phase is 5%.
Crown Royalty Share

ARF or MRF?

- Generally, wells spudded up to and including December 31, 2016 are qualified for ARF
  - royalty rate is based on a production and price sensitive formula

- Generally, wells spudded on or after January 1, 2017 are qualified for MRF
  - Royalty rate is a flat 5% until the well’s revenues reach the $C^*$ value (proxy for drilling and completion costs of the well)
  - When the well’s revenues exceed $C^*$, the Post $C^*$ royalty rate will apply

- Visit About Royalties at [http://www.energy.alberta.ca/AU/Royalties/Pages/default.aspx](http://www.energy.alberta.ca/AU/Royalties/Pages/default.aspx) for more details on MRF, qualification, royalty formulas, $C^*$ calculation and royalty calculators
Royalty Calculators for ARF and MRF

https://www.energy.alberta.ca/AU/Publications/Pages/Royalty-Calculators.aspx

Oil and Gas Royalty Calculators

Royalty Framework Calculator for wells spud on or after January 1, 2017
Effective January 2017 for wells spud on or after January 1, 2017 or those approved to opt in early to the Modernized Royalty Framework (MRF).

Royalty Framework Calculator for 2011 for wells up to and including December 31, 2016
Effective January 2011 for wells spud up to and including December 31, 2016, for the adjusted Alberta Royalty Framework (ARF).

Old Oil Royalty Calculators (note dates)

Alberta Royalty Framework Calculator (2009-2010)
Effective January 1, 2009 to December 31, 2010 for the Alberta Royalty Framework (unless the client chose Transitional Royalty rates for the well).

Original Basic Oil Calculator
This original oil royalty calculator was used from 1993 to December 31, 2008.
Ultra Heavy Oil Par Price

Oil par prices

The following par prices are used to determine the royalty volume payable to the Crown.

On this page:

To view the current par price, click on the latest month:

2019

Table 1. Par prices
Ultra Heavy Oil Par Price

March 23, 2017

INFORMATION LETTER 2017-12
Subject: Petroleum Royalty Regulation, 2009 (A.R. 222/2008) - Par Prices for May 2017 Production Month

This Information Letter provides the Crude Oil Category and Density, and the various prices for oil necessary to determine the royalty volume payable to the Crown.

<table>
<thead>
<tr>
<th>Category of Crude Oil</th>
<th>Density</th>
<th>May 2017 Par Prices $/M³</th>
</tr>
</thead>
<tbody>
<tr>
<td>Light Oil</td>
<td>less than 850 kilograms per cubic metre</td>
<td>$379.54</td>
</tr>
<tr>
<td>Medium Oil</td>
<td>greater than or equal to 850 kilograms per cubic metre and less than 900 kilograms per cubic metre</td>
<td>$336.15</td>
</tr>
<tr>
<td>Heavy Oil</td>
<td>greater than or equal 900 kilograms per cubic metre and less than 925 kilograms per cubic metre</td>
<td>$319.77</td>
</tr>
<tr>
<td>Ultra Heavy Oil</td>
<td>greater than or equal to 925 kilograms per cubic metre</td>
<td><strong>$268.33</strong></td>
</tr>
</tbody>
</table>
Crown Royalty Share (ARF)

Alberta Royalty Framework Oil Calculator (effective Jan. 1, 2011)

This Calculator was developed to assist industry with the Adjusted Alberta Royalty Framework formula changes.

Please note if you have previously used this calculator, code stored in your cache may return inconsistent results, to prevent this please clear your cache on return visits. If you have not used this calculator before you will not need to take this step. Future development will move this application to our server side to eliminate this issue.

Disclaimer

Press Tab to move through the entry fields. Clear this form for a new well entry.

1. Enter Par Price  
   Required  
   $258.33  

2. Enter Well Quantity  
   Required (no commas)  
   m³  
   230.0  

3. Crown %  
   Required  
   %  
   100.000000  

4. Enter Well ID  
   (Optional - for printing purposes)  

5. Enter Well Event Density  
   (Optional - for printing purposes)  

Calculate  
Clear Form
Crown Royalty Share (ARF)
MRF – C* Calculator

Alberta Modernized Royalty Framework C* Calculator

Alberta’s Modernized Royalty Framework (effective for wells spud after Jan. 1, 2017 or early opt-in participants) emulates a revenue minus cost royalty structure across all hydrocarbons (oil, natural gas and non-project oil sands).

The Drilling and Completion Cost Allowance (C*), is a proxy for completed well costs. It is a calculated value based on vertical depth, lateral length and the amount of proppant placed. The same C* formula is used regardless of hydrocarbon target. It determines the allowable revenue after which individual well sites begin paying higher royalty rates.

A company will pay a flat royalty of 5% on a well’s early production until the well’s total revenue, from all hydrocarbon products, equals C*. Afterwards, the company will pay higher royalty rates (Post C*) that vary depending on the resource and reference price of the commodity. Royalty rates decrease to match declining production rates when the well reaches a maturity threshold.

This calculator is a tool to help you estimate C*. See About Royalties for more information.

Disclaimer

C* Calculation

| TVD (True vertical depth) meter | 300 |
| TLL (Total lateral length) meter | 300 |
| TPP (Total proppant placed) | 100 |

Formula used for TVD < 2000:

\[
\text{ACCI} \times (1170 \times (\text{TVD} - 248) + 800 \times \text{TLL} + 0.6 \times \text{TVD} \times (1 \times \text{TPP}))
\]

Where ACC = 1

Calculate C* $317,670.00
Crown Royalty Share (MRF) Post C* Calculator

Part 1 - Royalty Price Component ($r_p$)

\[
\frac{(\text{Par Price} - \$251.70) \times 0.000071 \times 0.10000 \times 100}{\text{Par Price} - \$251.70} = \frac{268.33}{\$409.02} = 0.66 = 66 \%
\]

Part 2 - Adjustment for wells below maturity threshold ($r_q$)

\[
\text{Quantity} = 194.0 \text{ m}^3, \quad r_q = \frac{230.0}{\text{Quantity}} = 0.00 \%
\]

Part 3 - Royalty Rate ($r_p \times r_q$)

\[
r_p = 0.1110, \quad r_q = 0.00 \%
\]

Crown Royalty Share = Production x Crown % x Post C* Rate

\[
= 230 \times 100\% \times 11.18\% = 25.7
\]
Transitioning from NPR to OSR

• Non-Project wells where royalty is calculated under ARF, can apply for an OSR Project at any time, to transition to the OSR regime

• Non-Project wells where royalty has been calculated under MRF with the C* royalty rate will have 12 months to apply for an OSR Project, to transition to the OSR regime

• When the non-Project well is subsequently approved under the OSR regime, any NPR royalty paid prior to the OSR Project effective date will be recalculated to MRF Post C* royalty rates

* For further information, please see section 27 of the OSRR’09
Crown Agreement Royalty (CSR)

- Royalty terms, revenues and costs are specific to each Crown agreement.
- Pay cash royalty in accordance with terms prescribed in each Crown Agreement.
- Separate but similar reporting format to OSR reporting (cost and revenue categories may differ).
Oil Sands Royalty (OSR)

• Why generic Oil Sands Royalty regime?
  • To establish a single, clear and stable royalty regime with common rules that apply to all developers
  • To optimize oil sands development to benefit Albertans
  • To promote competitive and fair oil sands development

• Regime is “self-assessing” and principally based on a “revenues less costs” (R-C) approach.

• Requires that Projects be defined as distinct economic entities, to “ring-fence” the costs and revenues.

• In the absence of an OSR Project approval, Non Project Royalty (NPR) will apply
OSR Pre-requisites

Must apply for, and receive approval for, an oil sands royalty Project to qualify for OSR Royalty, otherwise, the production is subject to Non-Project Royalty (NPR)

- Oil sands developers must have an oil sands agreement (permit or lease)
- Oil sands developers must have an AER Scheme Approval
  - Apply to AER for development/scheme approval
- Oil sands developers must have an OSR Project
  - Apply to DOE for OSR Project approval
Royalty Structure for OSR

Principally, **Revenues less Costs** or “R - C”

- Project costs (C), allowed under the *Oil Sands Allowed Costs (Ministerial) Regulation (OSAC)*, are deducted against Project revenues (R) before royalty is applied
- Payout is defined as the time at which the Project has recovered all investment costs, return allowances, capital and operating costs to date

**Pre-Payout Projects** (lower royalty rate)

- When cumulative Project costs exceed cumulative Project revenues

**Post-Payout Projects** (higher royalty rate)

- When cumulative Project revenues first equal or exceed cumulative Project costs

* Once a Project has reached Payout, it remains in Post-Payout
Revenue

Product Revenue

• Product volume at Royalty Calculation Point x Unit Price
• Product can be clean crude bitumen, blended bitumen, and/or other oil sands products

Project Revenue

• Sum of Product Revenues

Gross Revenue

• Project Revenue less diluent cost

Net Revenue

• Project Revenue less (Allowed Costs – Other Net Proceeds)
Revenue

Prior to 2009
• Revenue based on *actual* dispositions
  – Sales volume x Sales price

Effective 2009
• Revenue based on *deemed* dispositions
  – Volume at Royalty Calculation Point (RCP) x *applicable* Unit Price
Royalty Calculation Point (RCP)

- The point where royalty volumes are determined (Volume at RCP)
- Generally, the RCP is the first point of measurement where clean crude bitumen is obtained from the Project prior to disposition or prior to product being removed from Project boundary
Revenue Valuation

- Project
- RCP
- Effective 2009
- Prior to 2009
- Disposition

Prior to 2009:
Product Revenue based on Sales volume x Sales price

Effective 2009:
Product Revenue based on Volume at RCP x Unit Price (determined based on dispositions)
Unit Price in Revenue Valuation

- Depends on volume of Third Party Dispositions (TPD) in relation to the Volume at RCP

- \[ \text{TPD}\% = \frac{\text{Third Party Dispositions}}{\text{Volume at RCP}} \times 100 \]

- \( \text{TPD}\% \geq 40\% \) Arm’s Length (AL) Sales Price

- \( \text{TPD}\% = 0\% \) Bitumen Valuation Methodology (BVM) Price

- \( \text{TPD}\% < 40\% \text{ but } > 0\% \) Combination of AL Sales Price and BVM Price
Unit Price Formulas

• **AL Sales Price (when TPD% ≥ 40%)**

\[
\frac{(TC - HC)}{TD}
\]

Where:
• TC is the Total Consideration for 3\(^{rd}\) party dispositions
• HC is the Handling Charges in relation to 3\(^{rd}\) party dispositions
• TD (Total Disposition) is the 3\(^{rd}\) Party disposition quantity
Unit Price (AL Sales Price)

TPD% = (13,000 / 13,000) x 100
TPD% = 100%

Blend Volume @ RCP = 13,000m³
Blend AL Sales Volume = 13,000m³
Blend AL Sales Value = $6,000,000
Blend Handling Charges for AL Sales = $700,000

Blend Unit Price = (TC - HC) / TD
= (6,000,000 - 700,000) / 13,000
= $407.69/m³
Unit Price Formulas

- **BVM Price (when TPD% = 0%)**

\[
(TC - HC) + [(NQ \times P) + CD] \\
\frac{PQ}{PQ}
\]

Where:

- TC is the Total Consideration for 3\(^{rd}\) party dispositions
- HC is the Handling Charges for 3\(^{rd}\) party dispositions
- NQ is the remaining Bitumen Volume at RCP after 3\(^{rd}\) party dispositions
- **P is the Bitumen Adjusted BVM Price**
- CD is the Cost of Diluent in ‘Remaining’ Volume at RCP after 3\(^{rd}\) party dispositions, if product is blend
- PQ (Production Quantity) is the Volume at RCP
Bitumen Adjusted BVM Price “P”

- Bitumen Adjusted BVM Price = BVM @ Hardisty less BVM Transportation Allowance

- BVM @ Hardisty is the greater of:
  - the “floor price” for the month (published)
  - the price determined by the “BVM Model Calculator”

- Floor Price and BVM components used in the BVM Model Calculator are published by DOE monthly

Hardisty price is dependent on the bitumen density reported. Bitumen density must be calculated using the rolling average of the six most recent measurements and must be reported to 1 decimal place.

* For further information, please see Information Bulletin IB 2014-06
BVM Components

Bitumen Valuation Methodology components

This information can be used to calculate the bitumen value under the Bitumen Valuation Methodology (Ministerial) Regulation.

On this page:

Bitumen Valuation Methodology (BVM) reports  Contact  Related

Bitumen Valuation Methodology (BVM) reports

Information to calculate the bitumen value under the Bitumen Valuation Methodology (Ministerial) Regulation are available through Open government from 2009 to the most recent.

BVM model calculator

Use this BVM model calculator (XLSX, 83 KB) for example purposes only.
BVM Components

Bitumen Valuation Methodology (BVM) components

Summary | Detailed Information | Related

DESCRIPTION
This report provides the information used to calculate the bitumen value under the Bitumen Valuation Methodology (Ministerial) Regulation.

TAGS
BVM | BITUMEN VALUATION METHODOLOGY REGULATION | BITUMEN VALUE METHODOLOGY | BITUMEN | OIL SANDS

RESOURCES

BVM components : 2019
Last updated: April 23, 2019
MORE INFORMATION | DOWNLOAD

BVM components : 2018
MORE INFORMATION | DOWNLOAD

BVM components : 2017
MORE INFORMATION | DOWNLOAD

BVM components : 2016
MORE INFORMATION | DOWNLOAD
### BVM Components

<table>
<thead>
<tr>
<th>Production Month 2017</th>
<th>Exchange Rate (SCDN/SUS)</th>
<th>WCS Settlement Price (SUS/bbl)</th>
<th>WCS Dilbit Volume Fraction</th>
<th>WCS Bitumen Sybit Premium (SUS/bbl)</th>
<th>WCS Blend Density (Kg/m³ @ 15°C)</th>
<th>Condensate 'CRW' Allowance (SCDN/m³)</th>
<th>Condensate 'CRW' Density (Kg/m³ @ 15°C)</th>
<th>Bitumen Floor Price (SCDN/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>1.31099</td>
<td>37.19</td>
<td>0.94</td>
<td>0.07</td>
<td>923.5</td>
<td>433.59</td>
<td>729.5</td>
<td>105.26</td>
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<tr>
<td>Feb</td>
<td>1.31099</td>
<td>39.14</td>
<td>0.94</td>
<td>0.10</td>
<td>922.5</td>
<td>445.91</td>
<td>732.8</td>
<td>107.86</td>
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</table>

<table>
<thead>
<tr>
<th>Production Month 2017</th>
<th>Oil Sands Par Price (SCDN/tonne)</th>
<th>Third Party Disposition Threshold</th>
<th>Deemed Quality Adjustment (SCDN/m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>16.38</td>
<td>40.00 %</td>
<td>4.34171</td>
</tr>
<tr>
<td>Feb</td>
<td>17.41</td>
<td>40.00 %</td>
<td>4.34171</td>
</tr>
<tr>
<td>Mar</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>Apr</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>Jun</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>Jul</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>Aug</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>Sep</td>
<td>40.00 %</td>
<td>4.34171</td>
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<tr>
<td>Oct</td>
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<tr>
<td>Nov</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
<tr>
<td>Dec</td>
<td>40.00 %</td>
<td>4.34171</td>
<td></td>
</tr>
</tbody>
</table>

Deemed Quality Adjustment of $4.34171Cdn/m³ is effective from 2017-01 to 2019-12 only.
BVM Model Calculator

Alberta Oil Sands
Bitumen Valuation Methodology

$4.34171 / $CDim^3
<< Quality Adjustment, $CDim^3
<< (Bitumen_Sybit) - (Bitumen_Dilbit) Density Blending Difference, kg/m^3

Six measurements:
1. Rolling Average
2. Bitumen Density
3. WCS
4. Settlement
5. Debit
6. Bitumen Sybit

Condensate:

- "CRW" Value
- "CRW" Price
- "CRW" Density

Royalty Value

- Bitumen Hardisty
- $CDim^3
- $US/bbl

2017 Monthly Hardisty Bitumen Value Based on WCS Pricing, $CDim^3

2017 Monthly Hardisty Bitumen Value Based on WCS Pricing, $US/bbl

Link to official Crown Site: http://www.energy.alberta.ca/OilSands/1542.asp
Unit Price (BVM Price)

Blend Volume @ RCP = 13,000m³
Diluent in Blend Volume @ RCP = 3,000m³
Diluent Value in Blend Volume @ RCP = $3,000,000
Blend AL Sales Value = $0
Blend AL Sales Volume = 0m³

Blend Unit Price = \[\frac{[\text{TC} - \text{HC}] + ((\text{NQ} \times \text{P}) + \text{CD})}{\text{PQ}}\]

\[= \frac{[(0 - 0) + ((13,000 - 3,000) \times 337.42) + 3,000,000]}{13,000}\]

= $490.32/m³

Bitumen @ Hardisty = $347.42/m³
Transportation Allowance = $10.00/m³
Bitumen Adjusted BVM Price = $337.42/m³

TPD% = (0 / 13,000) \times 100
TPD% = 0%

AL Sales = 0
NAL Disposition 13,000m³
Unit Price Formulas

- **Combined Price (when TPD% < 40% but > 0%)**

\[
\frac{(TC - HC) + [(NQ \times P) + CD]}{PQ}
\]

Where:
- TC is the Total Consideration for 3rd party dispositions
- HC is the Handling Charges for 3rd party dispositions
- NQ is the remaining Bitumen Volume at RCP after 3rd party dispositions
- P is the Bitumen Adjusted BVM Price
- CD is the cost of diluent in ‘Remaining’ Volume at RCP after 3rd party dispositions, if product is blend
- PQ is the Volume at RCP

* For further information, please see section 32 of the OSRR’09
**Unit Price (Combined Price)**

- **Blend Volume at RCP** = 13,000m³
- **Diluent Value in Blend Volume @ RCP** = $3,000,000
- **Blend AL Sales Value** = $1,000,000
- **Blend AL Sales Volume** = 2,000m³
- **Diluent Value in Blend AL Sales** = $462,000

Blend Unit Price = \[\frac{[(TC - HC) + \{(NQ \times P) + CD\}]}{PQ}\]

\[= \frac{[(1,000,000 - 150,000) + \{(10,000 - 1,538) \times 337.42 + (3,000,000 - 462,000)\}]}{13,000}\]

\[= \frac{480.25}{m³}\]

- **TPD%** = \(\frac{2,000}{13,000} \times 100\)
- **TPD%** = 15.38%

- **Bitumen @ Hardisty** = $347.42/m³
- **Transportation Allowance** = $10.00/m³
- **Bitumen Adjusted BVM Price** = $337.42/m³

- **Diluent Added**
  - 462m³ (Diluent)
  - 1,538m³ (Bitumen)

- **NAL Disposition**
  - 11,000m³
  - 1,538m³ (Bitumen)
  - 462m³ (Diluent)

- **AL Sales**
  - 2,000m³
  - $1,000,000

- **RCP**
  - 13,000m³
  - 11,000m³
  - $150,000 (Blend Handling Charges for AL Sales)
Gross and Net Revenue

**Gross Revenue**
- Project Revenue less diluent cost

**Net Revenue**
- Project Revenue less (Allowed Costs – Other Net Proceeds)
Allowed Costs

- Eligible and Approved costs incurred prior to OSR Project Approval effective date, net of any revenues, will become the opening cost balance for the Project - Prior Net Cumulative Balance (Initial PNCB)

- Eligible and Approved costs incurred after OSR Project Approval effective date can be deducted against the revenues earned by the Project
  - Costs include:
    - Project Operations
    - Capital
    - Diluent
    - Project Expansion PNCB
    - Carry Forward Costs (Post-Payout Projects only)

* Please see the Oil Sands Allowed Costs (Ministerial) Regulation
Initial PNCB and Project Expansion PNCB

• **Initial PNCB:**
  - PNCB associated with initial Project approval
  - Reported in Schedule PRE 4 of Pre Payout EOPS as the opening cumulative cost balance

• **Project Expansion PNCB:**
  - PNCB associated with a Project amendment
  - Reported in the Allowed Costs section of the royalty form, as Project Expansion PNCB
  - Reported for the production month of the Project amendment, in the monthly/annual royalty submission (MRC/GFE/EOPS)

If the Initial PNCB is negative, the Project will become Post-Payout and the PNCB amount will be reported as Other Net Proceeds
Return Allowance

• A Return Allowance (rate of return or interest given on unrecovered investment) is calculated for OSR Projects until they reach a net revenue position, to recognize the cost of investing in capital intensive oil sands Projects.

• **In Pre-Payout:**
  • Return allowance is calculated for each *month* in the Period
  • Net Cumulative Balance $\times$ Long Term Bond Rate (LTBR)$_{\text{month}}$
  • Return allowance calculated for a *month* is an allowed cost in the *next month*

• **In Post-Payout:**
  • Return allowance is calculated for the *Period*, when the Period has a Net Loss
  • Return allowance calculated for a *Period* is an allowed cost in the *next Period*
Carry Forward Costs

- **Applicable to Post-Payout Projects only**

- If a Post-Payout Project has suffered a loss in a Period, the loss can be claimed as an allowed cost in the *next* Period

- A return allowance is calculated on the net loss in a Period, which can be claimed as an allowed cost in the *next* Period

- If the royalty payable for a Post-Payout Project in a Period is based on Gross Revenue, rather than Net Revenue, the difference (excess) between the Gross Revenue Royalty and Net Revenue Royalty in a Period is an allowed cost in the *next* Period

* For further information, please see section 3 of the OSAC
Cumulative Balance Carried Forward

- **Applicable to Post-Payout Projects only**

- Net Cumulative Balance is an allowed cost in the first Post Payout Period

- Last production’s month Return Allowance calculation is an allowed cost in the first Post Payout Period

- Sum these two amounts and report in the ‘Cumulative Balance Carried Forward Upon Payout’ row in the Allowed Cost section of the GFE and Post Payout EOPS
Other Net Proceeds

• Other Net Proceeds (ONP) are ‘a reduction of allowed costs’:

• Types of ONP:
  • Disposition of Assets and Non-Oil Sands Products Purchased by Project
  • Sale/Lease of Technology
  • Insurance and Legal Settlements
  • Custom Processing and Transportation Fees
  • Processing of Project Owner’s Non-Project Substances
  • Negative PNCB

• If the ONP for the Period is greater than the allowed costs for that Period, the ‘allowable ONP’ will be an amount equal to the allowed costs for the Period and the excess ONP will carry forward to the next Period as ONP.
Gross and Net Revenue

**Gross Revenue**
- Project Revenue less diluent cost

**Net Revenue**
- Project Revenue less (Allowed Costs – Other Net Proceeds)
Pre-Payout and Post-Payout Project Royalty

• **Royalty on Pre-Payout Projects:**
  • Prior to 2009, 1% x Gross Revenue
  • Effective 2009, $R_G\% \ast$ x Gross Revenue for Royalty Calculation

• **Royalty on Post-Payout Projects:**
  • Prior to 2009, greater of:
    • 25% x Net Revenue
    • 1% x Gross Revenue
  • Effective 2009, greater of
    • $(R_N \text{ Factor\%} \ast \text{x Net Revenue/Gross Revenue}) \times \text{Gross Revenue for Royalty Calculation}$
    • $R_G\% \ast \ast x \text{Gross Revenue for Royalty Calculation}$

Note: Gross Revenue for Royalty Calculation must be greater than or equal to 0.

* Pre-Payout Gross Royalty Rate (from 1% to 9%)
** Post-Payout Net Royalty Percentage Factor (NRPF) (from 25% to 40%)
*** Post-Payout Gross Royalty Rate (from 1% to 9%)
Oil Sands Regime (OSR) Royalty Rates

![Graph showing Oil Sands Royalty Rates](image-url)
Oil Sands Regime (OSR) Royalty Rates

- The following are calculated for each production month:
  - Pre-Payout Gross Royalty Rate ($R_G\%$)
  - Post-Payout Gross Royalty Rate ($R_G\%$)
  - Post-Payout Net Royalty % Factor (NRPF or $R_N\%$ Factor)

- Royalty percentages and supporting details are posted on DOE Oil Sands website by the 5th business day following the production month at:

- Royalty rate formulas are prescribed in the Oil Sands Royalty Regulation, 2009
Royalty Reporting

• **NPR**
  - Monthly Royalty Reporting:
    - Non-Project Royalty Submission (NPR)
  - Annual Royalty Reporting:
    - N/A

• **OSR & CSR**
  - Monthly Royalty Reporting:
    - Pre-Payout Projects: Monthly Royalty Calculation (MRC)
    - Post-Payout Projects: Good Faith Estimate (GFE)
  - Annual Royalty Reporting:
    - End of Period Statement (EOPS)

• **A Statement of Approval (SOA) is required for MRC / GFE / EOPS.**
• **An External Auditor’s Opinion is required for EOPS for Oil Sands Projects with average daily production of 1,590 m3 or greater for the Period.**
Royalty Reporting

Updated External Auditor’s Opinion

- Operators of a Project that submit an amended End of Period Statement (EOPS) are required to provide an updated external auditor’s opinion if the reporting changes result in a 10% increase or decrease in any of the following categories from the previous EOPS that required an external auditor’s opinion:
  - Royalty Payable
  - Revenue for Royalty Calculation
  - Total Allowed Costs

- File amended External Auditor’s Opinion(s) annually by next March 31

* For further information, please see Information Bulletin IB 2015-06
Other Reporting

- **Costs and Reporting Enhancements (CARE)**
  - More detailed breakdown of revenue, operating and capital cost information on quarterly or annual basis

- **Operator’s Forecast**
  - Annual forecasts (current + 14 years effective November 2017) including estimates for:
    - Production
    - Strategic and sustaining capital
    - Operating costs

- **Cost Allocation Methodology Reporting (CAMR)**
  - Cost Allocation Order will provide specific reporting requirements

- **Additional reporting requirements under section 27(6) of the OSRR’09**
Common Reporting Issues

- **Submission with errors**
  - Initial report received back from ETS does not confirm successful submission validation. Validation results from OASIS will indicate whether submission was successful or requires further attention. Submissions with errors will be considered not to have been furnished as per section 5 of the OSRR’09

- **Failure to file required reporting**
  - Ensure all Non-Project Well and Project reporting is provided as per the OSRR’09

- **Submission late in the day of the filing deadline**
  - Ensure adequate time if submitting on the due date. OASIS processes and responds to submissions about every 2 hours up to 4:30pm
Penalties

Monthly & Annual Reports, Operator’s Forecast
• Submissions not received by their applicable due date are subject to a penalty of $5,000 for each month or part of a month during which the failure continues

Adhoc Reports
• Reports requested under section 40(1) of the OSRR’09 that are not received by the deadline specified in the notice given by the Minister are subject to a penalty of not more than $5,000 for each day during which the failure continues

CARE Reports
• Submissions not received by their applicable due date are subject to a penalty of not more than $5,000 for each month or part of a month during which the failure continues

Reporting requested under section 27(6) of the OSRR’09 (reporting requirements under MRF that apply to non Project wells)
• Submissions not received by their applicable due date are subject to a penalty of not less than $1000 and not more than $5,000 for each month or part of a month during which the failure continues

* For further information, please see section 44 of the OSRR’09
Penalties (Example)

- Assume current date = May 14, 2019
- No monthly royalty submissions received to date for January – March production. What late-filing penalties apply?

Jan: $5,000 x 3 months (March – May): $15,000
Feb: $5,000 x 2 months (April – May): $10,000
March: $5,000 x 1 month (May): $5,000

Total: $30,000
Interest Payable to the Crown

• If an amount is not paid by the day on which it is required to be paid, interest on the amount is payable to the Crown by the person required to pay the amount.
  • Some examples are:
    • Non-Project Royalty
    • Project Royalty
    • Penalties
    • Interest

* Simple Daily and Compounded Monthly Interest applies
Interest Payable by the Crown

- Interest is paid by the Crown only in specific circumstances:
  - Some examples are:
    - Post-Payout End of Period Statement overpayments
    - Non-Project Royalty overpayments

* Simple Daily Interest applies
* For further information, please see section 45(6) of the OSRR’09
Questions?