Alberta Oil Sands Royalty Guidelines

Principles and Procedures

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Contents

Notice

The guidelines outlined in this document are based on the following acts of legislation and regulation:

- *Mines and Minerals Act*, RSA 2000, c. M-17 (the Act),
- *Oil Sands Royalty Regulation, 1997* (AR 185/97) (OSRR97),
- *Oil Sands Royalty Regulation, 2009* (AR 223/2008) (OSRR09),
- *Oil Sands Allowed Costs (Ministerial) Regulation* (AR 231/2008) (OSACR) ,
- *Bitumen Valuation Methodology (Ministerial) Regulation* (AR 232/2008) (BVMR), and
- *Mines and Minerals Dispute Resolution Regulation* (AR 170/2015) (MMDRR)

The Act, the regulations and the guidelines themselves are subject to regular reviews by the Department. They are amended as required, in response to changing circumstances and business needs.

These guidelines reflect the Department's policies and procedures as of January 1, 2018, based on the most recent amendments to the regulations, unless otherwise indicated. *Oil Sands Royalty Regulation, 1997* applies to cost disputes for the open years of Royalty Amendment Agreements (RAA). Notification will be issued when the guidelines are revised again.

The Alberta Oil Sands Royalty Guidelines are produced for the convenience of readers. The guidelines provide a general understanding of the oil sands royalty legislation and the operating procedures used when royalty-related legislation is applied.

> The guidelines have no legislative sanction. Should the guidelines conflict with the Act or the OSRR97, the OSRR09, the OSACR, and the BVMR, the Act and regulations will prevail.
>
> Should the guidelines conflict with the Department's Information Letters or Information Bulletins published prior to January 1, 2018, the guidelines will prevail.

The Act and the Regulations

Copies of the Act, the OSRR97, the OSRR09, the OSACR, the BVMR, and related legislation are available through the Queen's Printer:

In Edmonton:

Main Floor • Park Plaza 10611 – 98 Avenue Edmonton, Alberta T5K 2P7

Phone 780.427.4952

Fax 780.452.0668

E-mail: qp@gov.ab.ca

Website http://www.qp.alberta.ca/Laws_Online.cfm

Free, online copies may be downloaded from the Queen's Printer or the Department's website.

For information or inquiries regarding the guidelines, please contact the appropriate representative listed in Appendix G, "Contact Information".

Related Legislation

The following legislation applies to specific aspects of oil sands development and administration:

- *Mines and Minerals Act,* RSA 2000, c. M-17
- *Oil Sands Royalty Regulation, 2009* (AR 223/2008)
- *Oil Sands Allowed Costs (Ministerial) Regulation* (AR 231/2008)
- *Bitumen Valuation Methodology (Ministerial) Regulation* (AR 232/2008)
- *Mines and Minerals Administration Regulation* (AR 262/1997)
- *Mines and Minerals Dispute Resolution Regulation*(AR 170/2015)
- *Oil Sands Tenure Regulation, 2010* (AR 196/2010)
- *Oil Sands Conservation Act,* RSA 2000, c. O-7
- *Oil Sands Conservation Rules* (AR 76/1988)

Parts of the following legislation also apply to oil sands development:

- *Petroleum Royalty Regulation, 2009* (AR 222/2008)
- *Petroleum Royalty Regulation, 2017* (AR 212/2016)
- *Natural Gas Royalty Regulation, 2009* (AR 221/2008)
- *Natural Gas Royalty Regulation, 2017* (AR 211/2016)
- *Métis Settlements Act* RSA 2000, c. M-14

The following legislation continues to apply for limited purposes only:

- *Oil Sands Royalty Regulation, 1997* (AR 185/1997) – Only applicable for projects having cost disputes or in open years of Royalty Amending Agreements.

- *Innovative Energy Technology Regulation* (AR 250/2004)
- *Drilling Royalty Credit Regulation* (AR 245/2009)

About This Document

The Alberta Oil Sands Royalty Guidelines are designed to:

- Help oil sands lessees understand and comply with the Act and oil sands regulations.
- Help oil sands lessees determine, calculate and report the share of royalty payable to the Crown.

Conventions Used in this Document

The Minister refers to Alberta's Minister of Energy.

Note that under Section 9(1) of the Government Organization Act, the Minister may in writing delegate any power, duty, or function imposed on him by the Act or the Regulations to staff of the Department.

The Department refers to Alberta Energy.

The Act refers to the Mines and Minerals Act.

The terms **generic, generic oil sands royalty and generic oil sands royalty regime** refer to the royalty calculation and collection methodology outlined in the regulations.

An **oil sands royalty (OSR) Project** is an oil sands Project for which an approval under section 11(1) of the OSRR09 is in effect.

Chapters and Appendices

The Alberta Oil Sands Royalty Guidelines address a number of areas:

- Chapter 1 - looks at the evolution of Alberta's oil sands royalty (OSR) system and provides an overview of how the current generic oil sands royalty regime works.
- Chapter 2 - explains the requirements for OSR Projects.
- Chapter 3 - describes the process of applying for an OSR Project.
- Chapter 4 - provides an introduction to OSR calculation.
- Chapter 5 - describes capital assets.
- Chapter 6 - provides definitions for accounting concepts such as affiliates and non-arm's-length transactions, and explains how these concepts apply to OSR calculations.
- Chapters 7 - describes the requirements for royalty reporting and payment.
- Chapters 8 and 9 - deal with advance rulings, dispute resolution and appeals.

The appendices include

- Appendix A - Oil Sands Royalty Glossary.
- Appendix B - Forms (OSR) Submission List
- Appendix C - Cost Analysis and Reporting Enhancement (CARE) Forms
- Appendix D - CARE - Glossary
- Appendix E - CARE - Timeline and Timetable
- Appendix F - Abbreviations Used in Guidelines
- Appendix G - Contact Information
- Appendix H - Electronic Transfer System (ETS) – File Naming Conventions
- Appendix I - Oil Sands Royalty Reporting Interest Rules
- Appendix J - Cost Allocation Business Rules
- Appendix K – Discretionary Cost and Advance ruling Request Form

Additional Information

The Alberta Oil Sands Royalty Guidelines presume the readers have familiarity with the geography and development history of Alberta's oil sands, as well as their strategic importance to the province's economy. The guidelines also presume the reader's familiarity with the technology and economics of oil sands production and with the Alberta tenure system through which Crown-owned oil sands rights are leased and administered. If the Guidelines do not provide an answer, questions should be directed to the contacts identified in Appendix G or the Department's website at <www.energy.gov.ab.ca> under 'Oil Sands', then 'Oil Sands Contacts'.

1. Alberta's Oil Sands Royalty System

Alberta's tenure system enables the Crown to grant the right to win, work, and recover oil sands products, and to realize economic benefits through bonus and rent. Royalty is then paid to the Crown as a share of the revenue generated from the development of the oil sands resource. Crown mineral rights are managed by the Department on behalf of the citizens of the province. The Alberta Crown owns 97% of oil sands mineral rights; freehold owners hold the remaining 3%.

1.1 Oil Sands Royalty: A Look Back

In the 1960s, when the first commercial oil sands projects were launched, oil sands development was a very costly, high-risk process. Oil sands technology and engineering were in their infancy and developers faced formidable challenges in extracting bitumen.

To encourage the development of the oil sands industry in the face of these early challenges, the Alberta government adopted a royalty approach in which the Crown shared the risk by taking a minimal royalty until an oil sands project reached "payout", meaning the gross cumulative revenues exceeded the gross cumulative costs for the first time. Royalty terms for significant oil sands projects were negotiated on a project-by-project basis and specified in individual Crown agreements. Minimum royalty rates on gross revenue (pre-payout) ranged from 1% to 5%. Royalty on net revenues (post-payout) ranged from 25% to 50%. Gas royalties were waived in some cases.

A project-by-project approach to royalty made sense in the formative years of the oil sands sector. It allowed for flexible royalty arrangements to accommodate the unique requirements of each project and address project-specific concerns. It was manageable because there were relatively few commercial operations. Through enabling the early projects to reach success, it helped to build a body of knowledge and experience that formed the basis of the current oil sands legislation.

As oil sands development advanced, research and technological innovations contributed to the development of new tools and processes that reduced production costs. More companies got involved in oil sands development as oil prices increased. A different approach to royalty was needed to address the needs of a growing oil sands sector.

1.1.1 The Impetus for Change

In 1993 the joint industry–government National Task Force on Oil Sands Strategies was launched by the Alberta Chamber of Resources.

The task force identified Alberta's ad hoc, project-specific royalty structure as a barrier to oil sands development. The ad hoc structure created uncertainty about what royalty terms would apply to future investments, because a Crown agreement establishing royalty terms had to be negotiated for each new oil sands development.

In its 1995 report, the task force outlined a comprehensive new approach for Alberta's oil sands industry. A key recommendation, accepted by the Government, was that oil sands royalty should be established through legislation rather than individual Crown agreements. That is, the royalty regime should be generic: the same rules should apply in the same situations and the same standardized royalty terms should apply to all new

OSR Projects.

The Government of Alberta began work to develop a generic oil sands royalty regime, which incorporated many of the Task Force's recommendations:

- Retain Alberta's competitive advantage among world energy investment opportunities;
- Fairly distribute resource income between producers and owners;
- Be responsive to changes in the economic environment faced by the industry;
- Minimize distortions in economic activity and investment;
- Generate a fair distribution of royalties and taxes across producers; and,
- Reduce opportunities to avoid compliance while minimizing administration and compliance costs.

1.2 Generic Oil Sands Royalty

Alberta's generic oil sands regime has been in effect since the 1997 implementation of the OSRR97. The OSRR97 adopted the "revenue minus cost" approach, which was chosen for Alberta's oil sands due to the high cost, long lead time, and the associated high risk nature of oil sands development.

The OSRR97 was replaced by three regulations – OSRR09, OSACR, and BVMR – in 2009 with the implementation of the New Royalty Framework[1]. The Framework called for higher royalty rates tied to the WTI and detailed description of Project costs which may be allowed for royalty calculation. The Framework also marked the last period in Alberta's oil sands history when Crown Agreement projects were re-negotiated before those projects fully transitioned to the generic regime in 2016.

In 2017, oil sands related regulations, namely the MMAR, MMDRR, OSRR09, OSACR, and BVMR, were amended to implement the Royalty Review Advisory Panel's recommendations. [2]

1.2.1 What Is "Generic" Royalty?

The current oil sands royalty regime is called generic because consistent royalty rates and rules apply to all oil sands projects approved under the regime. The royalty rates are established through legislation rather than individual Crown agreements. The rates are the same for all new OSR Projects and are not subject to negotiation.

[1] On September 18, 2007 "Our Fair Share - Report of the Alberta Royalty Review Panel", was released. The Report was a review of Alberta's royalty and tax regimes with the goal of ensuring Albertans are receiving a fair share from energy development through royalties, taxes and fees.

[2] The mandate of the Royalty Review Advisory Panel (2015) was to identify opportunities to optimize Alberta's royalty framework for crude oil and liquids, natural gas and oil sands.

1.2.2 A "Revenue Minus Cost" Approach

Alberta's project-based generic oil sands royalty regime operates on the principle of revenue minus cost, or "net revenue". Royalty is paid at one of two rates, depending on the OSR Project's financial status. The deciding factor is the OSR Project's payout status.

An OSR Project has "reached payout" when its cumulative revenues exceed its cumulative eligible costs, for the first time.

Before the payout date, the applicable royalty is 1% to 9% of the OSR Project's gross revenue, depending on oil prices. This low gross rate recognizes the high costs, long lead times and high risks associated with oil sands investment. It avoids imposing high royalty payments during the critical start-up stages of the OSR Project.

After the payout date, the applicable royalty is the greater of:

- The OSR Project's gross revenue multiplied by the gross royalty rate, or
- The OSR Project's net revenue multiplied by the net royalty rate.

Note: The net royalty rate varies from 25% to 40% depending on oil prices.

This feature of the generic regime links the Crown's return to the success of the OSR Project. The Crown does not receive a significant share of royalty until an OSR Project is profitable and the developer has recovered their investment. This approach encourages developers to innovate and maximize the efficiency of their operations.

Reaching Payout: What Are the Implications?

> After reaching payout, an OSR Project's royalty rate and reporting obligations change. In addition, the post-payout royalty calculation is variable. For example, if revenues fall, or if eligible costs increase as a result of an approved expansion, the "gross royalty" rate can apply even if an OSR Project has reached payout. Net royalty payment, based on net revenue, will resume when net revenue royalty exceeds gross revenue royalty. NB: Once an OSR Project reaches payout it is always considered to be in payout, even if it subsequently pays gross revenue royalty for some period of time.

Definition of a "Period"

> A Period is defined in OSRR09 as each calendar year, or partial calendar year comprising the months between the effective date of a Project and the date the approval of the Project is revoked.
>
> If a Project reaches payout during a calendar year, the parts of the calendar year before the payout date, and the part of the calendar year following the payout date, are treated as separate Periods.
>
> Periods include only full months. The effective date of a Project is the first day of the month. Likewise, a post-payout Period always begins on the first day of the month in which payout occurs.

1.2.3 Objectives

Alberta's royalty systems are designed to capture the fair share of the value of mineral and energy resources for the benefit of Albertans.

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

- Encourage the development of the oil sands while ensuring an optimal 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,
- Foster development, because investors expect to make a reasonable profit from oil sands ventures. The Government of Alberta does not provide grants, loans, loan guarantees, or any other "special deals" to oil sands lessees.
- Ensure that investment in the oil sands provides developers with a rate of return that is competitive with other petroleum development opportunities around the world.

1.2.4 Applicability: Who Pays Generic Royalty?

Oil sands developers who wish to pay royalty under the generic royalty regime must apply to have their projects approved as OSR Projects under the provisions of OSRR09 (see Chapter 3 of this guideline, "Applying for Generic Royalty Terms)".

1.2.5 Components of the Generic Royalty Regime

Alberta's generic royalty regime includes three components:

- The *Mines and Minerals Act*,
- The oil sands royalty regulations:
  - *Oil Sands Royalty Regulation, 1997 (OSRR97)* ;
  - *Oil Sands Royalty Regulation, 2009 (OSRR09)* ;
  - *Oil Sands Allowed Costs (Ministerial) Regulation (OSACR)* , and
  - *Bitumen Valuation Methodology (Ministerial) Regulation (BVMR)*.
- Policies, guidelines, and business rules developed by the Oil Sands Division.

1.2.5.1 The *Mines and Minerals Act*

The Mines and Minerals Act provides the general authority for the collection of oil sands royalties, including audit and recalculation provisions.

1.2.5.2 The Regulations

The OSRR09, OSACR, and the BVMR specify the details of the generic royalty regime. These guidelines cover these details in the following chapters:

- the “revenue minus cost” approach to oil sands royalty (Chapter 1)
- the components of an OSR Project (Chapter 2)
- the administrative processes for applying, amending or approving OSR Projects (Chapter 3)
- the revenues and allowed costs that are considered in calculating royalty (Chapter 4) and rules respecting capital assets and research costs (Chapter 5)
- the non-arm’s length and affiliate rules (Chapter 6)
- the requirements for royalty reporting and payment (Chapter 7)
- the process to obtain an advance ruling (Chapter 8) and procedures for appeals and dispute resolution (Chapter 9)

1.2.5.3 Business Rules

The business rules to implement the oil sands royalty regime are developed by the Department in consultation with the oil sands industry.

Examples of business rules include:

- certain cost allocation rules,
- cost of service rules.

Most of these rules are covered in the Guidelines, or in Information Bulletins published by the Department

1.3 Alternative Royalty Regimes

Developers who do not have an OSR Project approval under OSRR09, pay royalty as “non-project” operators under sections 26, 27 and 28 of the OSRR09, or under Crown agreements authorized by the Act:

- Non-project operators’ royalty share for oil sands products produced from well events is calculated according to the *Petroleum Royalty Regulation, 2009* or *Petroleum Royalty Regulation, 2017*, as appropriate, and paid in cash.
- Crown agreement operators pay according to the terms of their individual agreements.
- Non-project mining operations pay a royalty of 20% of the oil sands recovered.

2. Oil Sands Royalty (OSR) Projects

2.1 What is an OSR Project?

Under section 10 of the *Oil Sands Conservation Act*, the Alberta Energy Regulator (AER) may grant an approval to a person to construct facilities for, or commence or continue, a scheme or operation for the recovery of oil sands or crude bitumen.

The AER may also grant approvals for processing plants under section 11 of the Act.

These schemes or operations approved under section 10 of the *Oil Sands Conservation Act* are often loosely referred to as oil sands "Projects", but the term Project has a specific meaning under the OSRR09 as a Project defined and approved by the Department for royalty purposes under section 11 of the OSRR09.

A developer who wishes to pay royalty as a Project under the terms of the OSRR09 must apply to the Department under section 10 of that regulation (Applications). If the scheme or operation has been approved by the AER, and if it meets the requirements of OSRR09, it may be approved as an OSR Project under section 11 of the OSRR09.

An OSR Project approval is granted by Ministerial Order. The OSR Project approval order includes appendices and attachments that describe an OSR Project, specify its effective date and prior net cumulative balance, and detail all related terms and conditions.

Department approval is required for all new OSR projects, as well as for all amendments to currently approved OSR Projects. (See section 2.1.1.2.1, "Examples of OSR Project Amendments")

The Minister can revoke an approval in whole or in part if any of the following occur:

- The operator makes the request,
- A Project participant:
    - made any misrepresentation that is attributable to neglect, carelessness or willful default, or
    - committed a fraud in providing a document or other information under this Regulation.
- The requirements for the Project are no longer being met,
- The operator materially and repeatedly violates the Act,
- The Project is suspended or abandoned, or,
- Any of the supporting permits have expired or canceled.

A Note on Terminology

> An OSR Project description included as part of an OSR Project approval order specifies the lands, leases, operations, capital assets and other engineering systems and facilities that are considered to be "part of a Project" or "in a Project" or providing "support to a Project". In this way, it defines what revenues and costs are included in (or excluded from) the royalty calculation. Only approved operations and components are considered part of an OSR Project.
>
> The approved Project description for a new OSR Project is called the initial Project description. When a Project is amended, the approved description is referred to as the amended Project description.

2.1.1 Types of OSR Projects

OSR Project applications fall into one of the following categories:

- New OSR Projects.
- Amendments to previously approved OSR Projects (including expansions, amalgamations, and revocations).

2.1.1.1 New OSR Projects

OSR Projects are considered new if the Project approval under Section 11 of the OSRR09 or Section 15 of the OSRR97 (Prior Regulation) has not been previously issued. For example, non-project (well event) oil sands operations that previously paid royalty either under section 26 or 27 of the OSRR09, would be considered "new" when an application for approval as an OSR Project is made.

When a new OSR Project is approved, an attachment (schedule A) to the Ministerial Order outlines the initial project description 3 (See section 2.3 - "The Components of an Oil Sands Royalty Project Description"), which specifies the minimum requirements for:

- Lands and leases that have been approved as part of the OSR Project, or potentially includable lands and leases.
- OSR Project operations, including the wells, recovery method and technology that have been approved, the product that will be produced and the approved production capacity.
- Approved OSR Project facilities (including their related AER approval orders) and capital assets and engineering systems.
- The minimum number of wells in a project.
- Measured-use assets supporting the Project, if any, and,

[3] In general, only projects with more than one well will be issued an approval (however, approvals may be issued for wells testing experimental technology or for thermal pilot projects).

- Potentially includable lands and leases (PILL).

2.1.1.2 OSR Project Amendments

Oil sands lessees who wish to modify the terms of their OSR Project description must apply to the Department. If the application meets the requirements of the OSRR09 (under section 10 and 11) an amended OSR Project approval order may be issued. The approval order will include an amended OSR Project description.

OSR Project amendment applications are required, but not limited to:

- Expansions, which involve the addition of lands or facilities to the Project description (e.g., conversion of PILL land to project lands).
- Reductions, which involve the removal of lands or facilities from the OSR Project description.
- Reduction to remove a well not entirely in the Project.
- Amalgamations, which combine two or more approved OSR Projects into a single OSR Project.
- Changes in recovery method or technology.
- Changes in maximum production capacity.
- Addition of or changes to a cost allocation methodology.
- Changes to engineering systems, measured-use assets and integrated projects.

Ministerial Amendments

Pursuant to section 12 of the OSRR09, the Minister may in certain circumstances amend an OSR Project on the Minister’s own initiative subject to providing 30 days notice to the operator. However, if the Operator agrees, the Minister can issue an order with less than 30 days notice

Consulting with the Department

OSR project lessees are encouraged to discuss all proposed changes to their OSR Project (including potentially revoking a Project) with the Department to determine if a Project amendment application is required, or if what is proposed is consistent with the existing Project approval order appendices, schedules and attachments.

2.1.1.2.1 **Examples of OSR Project Amendments**

The following situations are examples of situations that trigger a need for an OSR Project amendment application to be made to the Department. This is not meant to be an exhaustive list of triggers, but it should reflect most situations that require an OSR Project amendment:

- The addition or removal of lands, surface areas, geologic strata or oil sands leases from an OSR Project description

- Changes to the facilities used by an OSR Project, resulting in a change to the types of oil sands products recovered or obtained pursuant to the OSR Project
- Any material changes to OSR Project operations
- Changes to OSR Project operations (from the existing OSR Project description) including, but not limited to, adding new phases or those described using different recovery and extraction methods
- Changes to an OSR Project description as set out in the existing OSR Project approval order appendices, schedules and attachments
- The addition or removal of any capital assets or engineering systems from the OSR Project. (Any addition of assets, located other than on OSR Project lands, must be specified)
- Any changes in services provided to the Project by measured use assets not included in the Project description
- Any other assets that are expected to be of material relevance to Project operations and that were not disclosed in a previous application for which an approval was granted
- Any additions or other changes to the listing and description of non-arm's length (NAL) transactions, expected to occur for the supply of any capital assets, goods or services for the Project, or for the supply of any capital assets, goods or services produced or generated other than for the purposes of the Project, disclosed in a previous Project approval
- Changes to a cost allocation methodology
- Amalgamation of two or more existing OSR Projects
- Changes to the AER scheme approval (see note below)

OSR Project amendment applications are not required when the Project's operator changes, or when changes are made to the working interest ownership. In these cases, the Project operator must notify the Department.

Note: When does a change to facilities or operations trigger an OSR Project amendment?

> Changes relating to OSR Project facilities or operations must be approved by the AER. When an amendment to an AER approval affects an OSR Project's recovery technology or processing capacity, the operator must apply to amend the OSR Project approval order as well. Operators should contact the Department to determine if an OSR Project amendment is required when their AER approvals change.

If an operator is uncertain whether a particular situation (identified above) would require an application, the operator should contact the Director of Project Engineering and Approvals, Oil Sands Operations Branch. (See Appendix G, "Contact Information")

2.1.1.2.2 **Application in the Alternative**

An application in the alternative means the Department will initially treat an application for an OSR Project expansion as an OSR Project amendment application. If, after reviewing the application it cannot be approved as an amendment, the application will be reviewed as an application for a new OSR project.

This option saves the applicant from having to submit a new application at a later date, potentially missing out on some prior net cumulative balance costs. See section 3.3.3.1.

2.2 OSR Project Requirements

Both new OSR Projects and OSR Project amendments must meet the following requirements.

2.2.1 AER Approval

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 10(1)(a)

As outlined in the regulation, for an oil sands operation to qualify for generic royalty treatment, its production schemes, operations, processing plants, wells and facilities must all be approved by the AER, as required under sections 10 to 15 of the Oil Sands Conservation Act.

Schemes, operations and facilities that do not have AER approval cannot be approved as part of an OSR Project.

AER application(s) and approval(s) must be filed with the Department as part of the application for OSR Project approval. The required AER approvals must be in place before an application for an OSR Project can be submitted.

2.2.2 Exclusions

Any portion of the land, facilities or assets, or activities and operations included in an AER-approved scheme may be excluded from an OSR Project description at the request of the applicant or at the discretion of the Minister.

Note

> Some types of capital assets used in an OSR Project may require approval by agencies other than the AER. For example, right of way for roads and ground water licenses may be granted by Alberta Environment and Parks. It is the responsibility of an OSR Project operator to ensure that all necessary approvals are obtained.

2.2.3 Minimum Considerations

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 11(1) and 11(2)

Before issuing an OSR Project approval order (or amendment including amalgamations), the Minister shall consider, without limitation:

- whether the OSR Project will be operationally integrated and operated under common management.
- whether any part of the OSR Project, other than a processing plant for the obtaining of synthetic crude oil, is more than 50 kilometres distant from any other part of the OSR Project.
- whether all the parts of the OSR Project, other than a processing plant for the production of synthetic crude oil, are geographically contiguous.
- whether any parts of the OSR Project will be located outside Alberta.
- whether the Project, if it is not an experimental or demonstration project:
  - will predominantly generate net revenue rather than net losses during the period in which the Project is expected to be conducted, and
  - can be expected to achieve payout, within a period of time that the Minister considers reasonable;
- the volume of the production from those wells specifically listed in the application.
- whether the Project is likely to exceed the maximum production capacity that the Minister considers appropriate.
- whether it is appropriate to specify a date and, what the date or dates should be.
- if the application for a Project includes new processing plant[4](s) or modifications to existing one(s) with estimated capital cost of $50 million or more.
  - whether it was accompanied by a Class 3 Estimate.

Note

> The Class 3 estimate is a new requirement intended to provide the Crown with greater certainty regarding plans for development. Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. Typically the Class 3 estimate would comprise at a minimum the following:
>
> - a high level summary of the class 3 project,
> - a design basis memorandum
> - plot plans
> - process flow diagrams
> - a schedule/ timeline
>
> A Class 1 or 2 estimate, or evidence that the facilities under review are being

[4] "processing plant" as defined in the Oil Sands Conservation Act means (i) a facility for obtaining crude bitumen from oil sands that have been recovered, (ii) a facility for obtaining oil sands products from oil sands, crude bitumen, de-asphalted bitumen or synthetic crude oil, or (iii) a stand-alone gas fractionating plant for obtaining methane, ethane, propane, butane or other similar light hydrocarbons from oil sands products;

> constructed or commissioned could be accepted, instead of a Class 3 estimate, by Alberta Energy.
>
> For specific questions, applicants and operators should contact the Department for clarification.

In issuing an OSR Project approval order, the Minister will take other information into account, as warranted by the specifics of the situation.

In addition to the above, the Minister shall consider before issuing an amended OSR Project approval order, the overall impact the amendment will have on the royalty payable to the Crown.

2.2.3.1 Operational Integration and Common Management

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 11

The Minister shall consider whether all OSR Project-related activities, facilities, and assets are substantially operationally integrated and operated under common management. This does not mean that an OSR Project may not have various owners, but planning, management and operations must be integrated so the OSR Project functions as a single unit for royalty calculation purposes.

2.2.3.2 Location Requirements

The Minister shall consider whether all components of an OSR Project are located in Alberta and comply with the location requirements specified below:

2.2.3.2.1 **Project Components (Except Upgraders)**

The Minister shall consider whether, except for upgraders, any component of an OSR Project is located more than 50 kilometres from any other part of the OSR Project. In exceptional circumstances, components located outside the 50-kilometre guideline may be considered for approval as part of an OSR Project.

2.2.3.2.2 **Geographically Contiguous**

In addition to the 50-kilometre guidelines, all parts of the OSR Project, except for upgraders, must be substantially geographically contiguous.

2.2.3.3 Project Economics

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 11(1)(e)

The Minister will take into consideration whether the OSR Project (if it is not a demonstration Project)

- will predominantly generate net revenue rather than net losses, and
- can reasonably be expected to achieve payout during the lifetime of the OSR Project or within a timeframe that the Minister considers reasonable.

2.2.3.3.1 **Economic Justification for Project Expansions**

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 11(2)(b) and 11(3)

The generic OSR regime has flexibility to facilitate staged development. Over time, an OSR Project may expand and grow. As long as the OSR Project's growth or development is reflective of existing operations, albeit carried out on a larger scale or larger production base, or with evolving technology (see Section 2.1.1.2, "

OSR Project Amendments") then the Minister may approve an amendment to the OSR Project after considering, in addition to the factors discussed above, the overall royalty impact of the expansion (unless in approving the OSR Project initially the Minister had already considered the proposed Project expansion).

2.2.3.3.2 **Economic Justification for Project Amalgamations**

The Minister may approve the amalgamation of two or more OSR Projects if this is economically justifiable. In making this determination, the same considerations relevant to the approval of an OSR Project amendment will be considered, including the impact on royalties.

2.2.3.4 Protecting the Crown's Royalty Share

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 11(1)(e)

The OSR Project should be viable, i.e., there must be a legitimate expectation of achieving payout within a reasonable time frame, and of profit, including a modest return on investment. The OSR Project should predominantly generate net revenues rather than net losses. The OSR Project must not be structured in a way intended to minimize the amount of royalty payable to the Crown.

In reviewing an OSR Project application, the Department looks at how the OSR Project description may impact the present value of future cash flows to the OSR Project lessees and the Crown. It considers whether the structure of the OSR Project is such as to unduly shift royalty away from the Crown.

2.2.3.4.1 **Crown Royalty and Project Amendments**

In the case of OSR Project amendments, the Crown considers the overall impact on the royalty payable.

DETERMINATION OF THE ROYALTY IMPACT

In the case of an amendment application for the expansion of an OSR Project, the Department compares the present value of royalty that would be payable by the amended OSR Project to the present value of royalty that would be payable by the original Project.

The long-term bond rate (LTBR) (see section 4.2.2, "The Return Allowance") is used as the discount rate in determining the present value of the royalty cash flows. The analysis assumes that expected costs and production data for all future years of both the existing OSR Project and the proposed expansion have been included in the application to amend the OSR Project

EXCEPTIONS TO THE ROYALTY IMPACT DETERMINATION

- Where the Minister in initially approving an OSR Project has already taken into account the proposed Project expansion, and determined that the Project with the inclusion of the proposed expansion was acceptable, the Department will not make another determination of the royalty impact of the expansion.

- Where a project is experimental it is not required to fulfil the economic requirements.
- Where the amendment is made solely to meet regulatory requirements.

2.2.3.4.2 **OSR Project Amalgamations**

Additional considerations may be used to evaluate the impact of OSR Project amalgamations. The Minister may, without limitation, consider the following in deciding whether to approve an amalgamation:

- There must be valid and sound technical or economic reasons for amalgamation (For example, avoiding stranded resources across boundaries, simplifying administration which should lower operating costs, applying a particular recovery process more efficiently across the amalgamated OSR Projects, etc.)
- Common management, ownership and integration – the OSR Projects must be managed and owned by the same company or group of companies. There must be a strong integration in the corporate structure and operation of the amalgamated OSR Project.
- Royalty impact – the amalgamated OSR Project must generate no less royalty than the individual OSR Projects, (This criterion protects the Crown's interest.)
- Except for upgraders, any part of the OSR Projects should be located within 50 kilometres of any other part of the OSR Projects.
- Same geological resource – the OSR Projects should produce from the same geological resource.
- Same processing plant – ideally, there should be one plant processing bitumen from the OSR Projects.
- Shared boundaries– the OSR Projects should share part of their boundaries.
- Same stream of oil sands sales product. The OSR Projects should produce products which contribute to the same stream.

2.3 The Components of an Oil Sands Royalty Project Approval

An OSR Project approval order will specify:

- The OSR Project name.
- A description of the Project.
- The OSR Project's prior net cumulative balance (PNCB).
- The effective date of the OSR Project.
- The maximum capacity of the Project.

An OSR Project description of an approved or amended Project must include:

- A description of the OSR Project operations, including the recovery method and technology that have been approved, and the approved production capacity.
- A listing of the kinds of oil sands products that will be recovered or obtained pursuant to the Project.
- The core and supporting assets, engineering systems, measured-use assets (if any) and percent of integrated shared operations (if any), including the cost allocation methodology.
- A map of the geographic boundary of the Project, and a description of the area and strata from which oil sands or oil sands products will be recovered.
- The lands and leases that have been approved as part of the OSR Project.
- A listing of the OSR Project facilities (including the required AER approval orders).
- The maximum production capacity, and the maximum period of time for expansion to the maximum production capacity, if that time is specified.

2.3.1 The OSR Project Name

The OSR Project name, in conjunction with a Department-assigned OSR Project approval order number, serves to identify the OSR Project in the Department's information systems and records.

Since ownership arrangements may change over time, the names of OSR Project owners should not be included as part of an OSR Project name.

2.3.2 The OSR Project Application and Approval Order Number

Upon creating an application through the Electronic Transfer System (ETS) an application number is assigned. Once the Department is satisfied the application is complete, a provisional project number is assigned. Provisional project numbers begin with the prefix “R”.

If the OSR Project application is approved, the “R” prefix from the provisional project number is replaced with the prefix “OSR” (for Oil Sands Royalty) to indicate approval.

If an OSR Project amendment application is approved, a letter is added to the OSR Project “OSR” number. For example, if OSR Project OSR 001 is amended, its OSR Project approval order number normally becomes OSR 001A. If it is amended again, its OSR Project approval order number normally becomes OSR 001B, then OSR 001C and so on.

The OSR Project approval order number forms part of the OSR Project approval document. Together with the OSR Project name, it identifies the OSR Project in the Department's information systems and records.

The “OSR” project approval order number or provisional project “R” number should be cited in all correspondence with the Department.

2.3.3 The OSR Project Lessee

The OSR Project lessee, also recognised as the OSR Project owner, is an individual and/ or individuals and/or corporation(s) that has leased the right to work, win and recover oil sands resources from a defined land area and subsurface stratum. The oil sands leases and permits detail the extent and duration of the lessee’s rights.

The lessees of an agreement may apply for approval of a proposed project for the recovery of oil sands and oil sands products.

An OSR Project may have single or joint ownership. When there is more than one lessee, each lessee’s equity share and obligations for royalty payment must be specified in an operating agreement.

Operating agreements must be filed with the Department as part of the application for OSR Project approval. The Department must be notified in writing if there is a change in OSR Project ownership.

Lessee: A Legal Definition

> As defined in section (1)(p) of the OSRR09, a lessee means, in relation to a Project, a lessee of an agreement, the location of which includes the whole or a part of the development area of an OSR Project.

2.3.4 Ownership Considerations

2.3.4.1 Freehold Interests

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 10(1)(b)

Freehold mineral rights cannot be included as part of a proposed OSR project. Only those oil sands rights owned by the Crown in right of Alberta can be included in an OSR Project.

2.3.5 The OSR Project Operator

Oil Sands Royalty Regulation, 2009, section 1(1)(v) and 10(2)(i)

The OSR Project operator is the person or corporation responsible for the management and operation of an OSR Project. OSR Project operators have the legal authority to represent the OSR Project and its lessees.

Note

> There may be more than one Project operator during a Project’s reporting Period(s); however, annual filing requirements are the responsibility of the

current operator effective at the end of the reporting Period.

OSR Project operators are responsible for:

- Filing Project reports, including Operator's Forecasts, monthly reports, End of Period Statements (EOPS), Cost Analysis & Reporting Enhancements (CARE), the Cost Allocation Methodology Report (CAMR) and Ad Hoc Reports. When an operator takes over a Project that operator is responsible for filing all reports including the EOPS even if it is for previous years,

  Oil Sands Royalty Regulation, 2009, sections 37, 38, 39 and 40

- Reporting material changes or errors in, or a material omission from report filings,

  Oil Sands Royalty Regulation, 2009, sections 41

- Maintaining records satisfactory to the Minister (OSR Project lessees have this responsibility as well),

  Oil Sands Royalty Regulation, 2009, section 42

- Paying royalty, although lessees may be responsible for royalty payments if the operator defaults,

  Oil Sands Royalty Regulation, 2009, section 7, section 29 and section 33

- Notifying the Department of a change in operator, change to contact information, Project ownership or other Project-related details. If the OSR Project operator should change, the Department must be notified in writing within 30 days. The Department will not accept royalty payments from, or release OSR Project-related information to, anyone but the authorized OSR Project operator,

  Oil Sands Royalty Regulation, 2009, section 36

- Paying penalties or interest charges levied under the terms of the Regulation (See section 7.11 – "Penalties" and section 7.12 – "Interest"

  Oil Sands Royalty Regulation, 2009, section 44 and 45

- Applying for an OSR Project, or an OSR Project amendment approval as the designee of the OSR Project lessees. In some cases, the OSR Project operator is also the lessee of the OSR Project. If the operator is not the sole lessee, a copy of the operating agreement to validate the operator's legal authority to represent the OSR Project lessees must be attached to the application. If the application is made by the OSR Project lessee's designee, documentation authorizing the designee to apply must be submitted together with the application. A letter from each OSR Project lessee clearly authorizing or consenting to the application being made by the designee is sufficient.

2.3.6 OSR Project Operations

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 14(1)(a)

OSR Project operations include all the activities required to recover, process and transport the outputs of the OSR Project (i.e., oil sands products) to the royalty calculation point (RCP) of the OSR Project.

2.3.6.1 Recovery Methods and Other Technology

Depending on the nature of an OSR Project, OSR Project operations may include activities such as:

- primary recovery
- secondary recovery (e.g., water flood)
- tertiary recovery (e.g., polymer flood and emulsion flood)
- thermal recovery
- solvent assisted recovery
- mining
- on-site transportation and processing (cleaning)
- on-site blending
- off-site processing (cleaning)
- provision of thermal energy, with or without electricity generation
- on Project storage
- upgrading.

The recovery methods and technology approved for an OSR Project are specified in the OSR Project approval order.

2.3.6.2 Oil Sands Products

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 1(1)(u) and 14(1)(b) and 32(9)

An OSR Project may produce one or more of the following products:

- raw crude bitumen
- cleaned crude bitumen
- blended bitumen
- synthetic crude oil
- sulphur, minerals, or other products obtained by processing or reprocessing oil sands
- “off-gases” produced from processing or reprocessing bitumen.

Note: Solution gas is not an oil sands product.

The approved production capacity for each approved product is specified in the OSR Project approval order.

2.3.7 Lands, Leases and Mineral Rights

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 14(1)(d)

An OSR Project comprises the surface area and subsurface oil sands strata that will be used to produce or process bitumen. These are defined as "Project Lands" and "Project Leases" in the OSR Project Approval order.

2.3.7.1 Project Leases

Project Leases are the mineral rights in the oil sands agreements that are included in a Project.

The subsurface strata in those oil sands agreements are identified by Zone Designations or Deeper Rights Reversion Zone Designations.

2.3.7.2 Project Lands

The surface areas included in a Project are usually identified by the Dominion Land Survey System description that indicates the relevant legal subdivision (LSD), Section, Township, Range and Meridian:

For example, LSD 01, Section 12, Township 64, Range 6, West of the 4th meridian (This can also be written as 01-12-064-06 W4M.)

2.3.8 Core or Supporting Assets

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 1(1)(f), 14(1)(c), 14(1)(c.1), 14(1)(c.2) and 14(1)(c.3)

A core or supporting asset means, in relation to a Project, a capital asset, an engineering system or a facility without which oil sands or an oil sands products could not be recovered or obtained, or an asset required for the operations or maintenance of such assets.

Assets

Examples of assets include:

- Bitumen production wells and batteries
- injection wells (including steam, solvent, etc.)
- observation or delineation wells
- source water wells
- water monitoring wells
- disposal wells
- roads, buildings, bridges, or electricity transmission lines

- camps
- airstrips
- pipelines used to connect project components or transport outputs to a RCP. (Sales pipelines are not eligible components of OSR Projects.)

Engineering systems
Examples of OSR Project engineering systems include:

- boiler feed water treatment system
- raw water system
- fuel gas system
- steam generation system
- electricity transmission system
- control system
- cooling water system
- instrument air system
- fire water system
- emergency power system
- potable water lines
- waste water lines, sewer lines and sour water lines
- slop oil lines
- pipe racks

Facilities

Examples of OSR Project facilities include:

- disposal facilities
- steam generation plants
- cleaning or treatment plants
- cogeneration plants
- upgraders and other facilities related to oil sands production.

If the Minister has approved a particular “core or supporting asset” or facility as part of an OSR Project description, eligible costs that are attributable to the approved asset, or facility are considered allowed costs that can be deducted for royalty calculation purposes. Any revenues attributable to non-project use of the approved asset, or facility must be reported as “other net proceeds (ONP)”.

The Minister will not approve core or supporting assets or engineering systems that do not meet the requirements for OSR Projects. Approved OSR Project facilities and assets are specified in the OSR Project approval order. Facilities, engineering systems and assets cannot be added or removed from an OSR Project unless permitted under the OSR Project approval order, or unless an application to amend the OSR Project approval order is approved by the Minister. (See section 2.1.1.2, "OSR Project Amendments")

2.3.8.1 Core or Supporting Asset Threshold

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 1(1)(oo) and section 14(2)

The Minister may only include a core or supporting asset in an OSR Project if the sustained use of the asset for the purposes of the OSR Project over the remaining useful life of the asset is expected to (and continues to) meet or exceed the OSR Project use threshold. If an asset is used by one or more affiliated Projects, it may be included in one of the Projects if it is almost exclusively used by those affiliated Projects.

2.3.8.2 Partial Inclusion of Assets

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 14(4), (5), (6), (7), (8), (11) and (14)

Only certain types of capital assets or engineering system may be partially included in an OSR Project description and only as provided under OSRR09. Some of the types of assets that can be partially included are:

- control system,
- cooling water system,
- instrument air system,
- fire water system,
- emergency power system,
- potable water lines,
- waste water lines,
- sewer lines,
- sour water lines,
- slop oil lines,
- pipe racks,
- roads,
- parking lots, and
- camps and airstrips and associated facilities.

The partial inclusion provisions are primarily to address situations where assets are shared between the royalty and non-royalty projects. A Project may use part of an asset from time to time, but that does not imply that a part of the asset will be included in the Project description.

If the OSR Project's use of a processing plant is not in the same proportion as its ownership, it is an ONP or an allowed cost.

The Minister may include in the OSR Project description all or part of a cogeneration plant. What parts of the plant are included depends on:

- how the products will be used, and,
- portion of the plant owned by the lessees.

The Minister shall not include measured use assets supporting the Project unless they meet the Project use threshold.

2.3.9 Criteria for Inclusion of Wells Completed Prior to the Project Effective Date in an Oil Sands Royalty Project

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 14(2)

The following provides the applicant of an OSR Project with the criteria that are applied by Alberta Energy in approving the inclusion of wells completed prior to the Project effective date in an OSR Project. Criteria that deal with wells completed after the proposed project effective date are normally specified in the Project description.

In alignment with the relevant provisions of the Regulation, the following criteria apply to wells that entirely reside on Project lands:

- As delineation of an oil sands reservoir is deemed to be necessary for Project operations, oil sands delineation wells drilled and abandoned on Project lands may be included in the Project. Any abandoned wells other than abandoned oil sands delineation wells will not be approved in the Project
- Oil sands delineation wells on Project lands (typically within Project leases) completed within the prior net cumulative balance period of the proposed project or Project amendment will be included in the Project
- For suspended wells or wells planned to be suspended within one year after the proposed Project effective date to be approved in a Project, the applicant needs to provide an economic assessment indicating that returning the suspended wells to operation is economically viable. The assessment will need to be stamped by a Professional Engineer (P. Eng.) on behalf of the applicant. The assessment should also include a proposed time frame for placing the suspended well in service and a general plan for how that is to be done
- Active or ready to be activated wells including bitumen production wells, water/steam injection wells, polymer/solvent/gas injection wells, water source wells, disposal wells and observation wells may be included in the Project if they are being used or will be used for Project purposes.

The following criteria apply to wells that reside partially or entirely off Project lands:

- abandoned or suspended wells will not be included in the Project
- oil sands delineation wells that reside off Project lands will not be included in

the Project

- for bitumen production wells that are not 100% residing on or under Project lands, the applicant needs to provide the data to confirm that the well produces from the Project lands.
- water source and disposal wells will not be included in the Project unless the applicant can demonstrate that their use is solely for Project operations. If it is subsequently determined that they are not being used appropriately for the Project, they will be removed from the Project.
- When a well event gets C* assigned, an applicant has up to one year from that date to request approval of that well event into an OSR Project. After one year, if the well has not been applied for, the well will never be allowed to form part of an OSR Project.

Note: the Drilling and Completion Cost Allowance (C*), based on average industry drilling and completion costs, is a proxy for well costs. It determines the allowable revenue after which individual well sites begin paying higher royalty rates (post-payout).

Observation wells will not be included in the Project unless the applicant can provide evidence showing that the well is a statutory requirement for monitoring the operation of another asset of the Project.

2.3.10 The Effective Date

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 1(1)(m) and Section 13

The effective date of an OSR Project is the date from which royalty begins to be calculated under the terms of the OSRR09.

A provisional effective date is assigned when the Department receives a complete OSR Project application. The provisional date is confirmed or revised (if necessary) during the OSR Project approval process. The OSR Project's effective date is identified in the OSR Project approval document.

The Department cannot assign a provisional effective date until a complete Project application—including the required AER approvals, complete cost and revenue data and OSR Project economic forecasts, as well as reserves information (refer to IB 2015-07)and a class 3 estimate, if applicable—has been provided. All required AER approvals must be in place before an OSR Project application will be accepted.

The effective date of the OSR Project or OSR Project expansion must not be earlier than any of the following:

- First day of the month in which the application was received.
- The first day of the month following the month in which the AER approval relating to the proposed project or the amendment relating to the expansion is approved.
- The first day of the month that precedes by nine months the month in which the Project or the amendment relating to the expansion is approved.

Note

> Failure in providing complete and accurate information, requesting changes to the OSR Project, or delaying in responding to questions or requests for more information can result in the approval being delayed and approval not being provided within nine months of the application being submitted. A delay in approval could make some prior net cumulative balance costs ineligible.

2.3.10.1 Subsequent AER Approvals and Effective Dates

Schemes, operations, and facilities that are approved by the AER after an OSR Project's effective date may not be considered part of the OSR Project. Therefore operators must contact the Department regarding any changes to their AER approvals, schemes, operations and facilities. Otherwise associated costs and revenues may not be considered as part of the royalty calculation for the project.

2.3.11 Prior Net Cumulative Balance

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 1(1)(cc), section 15

The prior net cumulative balance (PNCB) of an initial OSR Project is the balance of cumulative costs less cumulative revenues as of the OSR Project's effective date, as approved by the Minister.

A proposed OSR Project expansion will initially have its own PNCB. The PNCB of an OSR Project expansion is the balance of cumulative costs less cumulative revenues pertaining to the expansion. If the expansion is approved by the Minister, this PNCB will be incorporated in the remaining unrecovered balance of the expanded Project, as of the effective date of the amendment, if the Project was in pre-payout prior to the expansion, or will be treated as an allowed cost if the OSR Project had been in post-payout prior to the expansion.

An oil sands operator submits their calculations of PNCB as part of their application for OSR Project approval. It is reviewed by the Department as part of the application process. In the course of the review, the Department may remove or adjust costs found to be ineligible, or costs that are not properly supported by documentation. Applicants must submit summaries of authorizations for expenditures (AFE) or other corporate budgetary documents to substantiate their PNCB. The resulting Minister-approved PNCB is identified in the OSR Project approval document. PNCB verification, as with any cost or revenue item, is subject to an audit conducted by the Department. However, consistent with subsection 16(2) and 16(3) of OSRR09, an operator initiated amendment to the PNCB balance will not be allowed after the applicant has been notified that an audit of the PNCB has been completed.

Note

> If an OSR Project, or a pending or potential project, with an unrecovered balance is sold, the outstanding unrecovered balance remains fixed, regardless of whether the sales price was more or less than this amount. An OSR Project reaches payout when its cumulative revenues first equal its cumulative costs, i.e., there is no unrecovered balance. Payout is deemed to occur on the 1st day of the month in which this occurs. Once an OSR Project has reached payout it is always in payout, even if its net revenue becomes negative again.

2.3.11.1 Eligible Costs for PNCB

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 15(2)

Cost eligibility rules are specified in the OSACR.

The same rules in the OSACR that apply to costs in an approved royalty project also apply to determine eligibility of PNCB costs.

In addition, PNCB costs must occur during the PNCB eligibility period. Costs incurred prior to the PNCB period are not eligible for inclusion. Costs after the PNCB period should be reported as EOP costs, not in the PNCB.

2.3.11.2 Pre-Project Royalty

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 26 and 27

Non- Project royalty incurred during the PNCB Period and paid to the Crown under section 26 or 27 of the OSRR09, or possibly under a Crown Agreement, is eligible for inclusion as a cost in PNCB calculations for OSR Projects.

Such royalty must continue to be reported and remitted to the Crown even after an application for an OSR Project or amendment has been made. After receiving an OSR Project approval, the applicant must submit OSR royalty End of Period Statements (EOPS) commencing with the end of the first Period for the OSR Project. The non-Project royalty reported for the Period between the effective date and the approval date of the OSR Project (up to a maximum of 9 months) will be reversed and the amounts paid applied to the OSR Project Royalty after the effective date.

2.3.11.3 Amounts excluded from PNCB

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 15(3) and
Oil Sands Allowed Costs (Ministerial) Regulation (AR 231/2008)

The person submitting an application must ensure the amounts reported as a PNCB are accurate and are eligible under the provisions of the regulations. In addition, the Minister shall determine whether the following amounts should be excluded from determination of an OSR Project's or an OSR Project expansion's PNCB when the:

- costs were incurred during periods in which oil sands development was substantially suspended or abandoned,
- costs that would not qualify as allowed costs (under OSACR) had they been incurred after the OSR Project's effective date,
- any costs to the extent they were reduced by any credit or discount received by the operator or lessee of the OSR Project,
- any costs that are not evidenced by original documentation satisfactory to the Minister,
- the costs in respect of which Innovative Energy Technology Program (IETP) costs have been established, or,
- costs associated with assets or activities not included within the scope of the approved OSR Project.

2.3.11.4 Amounts to be Deducted from the PNCB

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 15(4)

When determining the PNCB of an OSR Project or an OSR Project expansion, the Minister shall take into consideration whether amounts should be deducted for Project substances or other revenues that would have been considered other net proceeds had it been received after the effective date.

2.3.11.5 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 15(2)(a) to (c)

The PNCB calculation of an OSR Project is limited to costs incurred and revenue generated within five years of the Project's effective date. Costs incurred or revenue generated more than five years before an OSR Project's effective date are not eligible for inclusion in PNCB calculations.

2.3.11.6 Amendments to PNCB

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 16

The Minister may, if requested by the operator of the OSR Project or on the Minister's own initiative, amend the OSR Project's PNCB. PNCBs shall not be amended after the Minister has concluded an audit, or four years after the effective date of the OSR Project, OSR Project Expansion or Prior Project expansion. This limitation does not apply if a PNCB amendment is made necessary by reason of fraud or misrepresentation attributable to neglect, carelessness or willful default.

The Minister shall notify the operator of the OSR Project, at least 30 days before amending the PNCB of an OSR Project, OSR Project expansion or Prior Project expansion.

3. Applying for Generic Royalty Terms

3.1 When Is an Application Required?

This chapter builds on Chapter 2, which provides a technical explanation of the oil sands royalty Projects. Chapter 3 details the administrative aspects of the application process.

The generic OSR regime does not automatically apply. By default, royalty is payable under Sections 26 and 27 of the OSRR09. Oil sands lessees who want to pay royalties under the generic royalty regime must apply for approval of new OSR Projects and for all significant amendments to currently approved OSR Projects.

3.2 Who Can Apply?

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 10

Applications for a new OSR Project approval or for an approval of an amendment (for a current OSR Project) can be made by:

- the lessee of an agreement,
- the OSR Project lessee's designee.
- OSR Project lessees may authorize another individual or corporation to make the application on their behalf. In most cases, the lessee's designee is the OSR Project operator.

If the application is made by the OSR Project lessee's designee, documentation authorizing the designee to apply must be submitted together with the application. A letter from each OSR Project lessee clearly authorizing or consenting to the application being made by the designee is sufficient.

If the application deals with an OSR Project expansion, documentation confirming the lessee of an agreement being added by the proposed expansion has consented to the application, must be submitted.

3.3 The Application Process

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 10 and 11

3.3.1 Consulting with the Department

Oil sands lessees are encouraged to consult with the Department about their applications for OSR Project approvals and amendments. The Department can provide guidance and advice about the suitability of a proposed project or amendment and about factors that should be addressed in preparing the application.

Questions about specific applications or about the application process may be directed to the Director of Project Engineering and Approvals, Oil Sands Operations Branch, Resource Revenue and Operations Division. (See Appendix G, “Contact Information”)

3.3.2 Making an Application

Applications for OSR Project approval must follow the format specified by the Department.

The application must be submitted electronically through the Department’s Electronic Transfer System (ETS). The applicant needs an authorized ETS Account prior to accessing the Oil Sands Administration & Strategic Information System (OASIS) service where the OSR Project Application form is available.

To receive access to the ETS, an ETS Account Set Up/Change Form must be submitted to the Department. The ETS manuals and the ETS Account Set Up/Change Form are available from the Department’s website: http://www.energy.gov.ab.ca/, from “Related Links”, navigate to “Electronic Transfer System (ETS)”

OASIS is a comprehensive secure automated system that allows the Oil Sands Operations Branch to better manage its strategic and administrative activities. OASIS clients will be able to create, edit and submit an OSR Project Application online.

OASIS collects specific OSR Project information to ensure a complete up-to-date application for each OSR Project Application is submitted.

To provide support to the OASIS application, an online training module is available for the submission process. From the Department’s website, navigate to “Oil Sands”, then to “Electronic Transfer System (ETS)”, then link to “Online Learning” Portal. Users are required to complete the self-registration process the first time they access the Department’s Online Learning Portal. Upon access to the portal select Knowledge Resources (as listed in the table below), and then scroll to the OSR resource titles to view the training modules.

OSR Applications Overview	This module provides an overview of the OSR Applications Online Training as well as brief overview of the web-based system for submitting OSR Project Applications.
OSR Applications Roles	This module focuses on the various roles involved in submitting an OSR Project Application.
Create New OSR Project Application	This module provides the procedures for creating and submitting a New OSR Project Application.
Create an Amendment OSR Project Application	This module outlines the processes required to create an Amendment for an OSR Project, and Amalgamation for one or more OSR Projects.
Manage Work in Progress	This module describes the process for retrieving saved OSR Project Applications.
Generate OSR Project Application Reports	This module describes the various reports that can be generated for a new OSR Project Application.

3.3.3 Completing the Application in OASIS

3.3.3.1 "Application" Type

OASIS requests the applicant to indicate the type of OSR Project approval being applied for. OSR Project applications may be for:

- new projects
- amendments to approved OSR Projects, including
  - expansions
  - amalgamations
  - other significant changes to the project description.

Applications for OSR Project expansions may be denied if they do not meet the OSR Project Amendment requirements. (See section 2.2 "OSR Project Requirements"). This could require the applicant to re-apply to have the expansion proposal reviewed as a new OSR Project. Then the OSR Project effective date could be no earlier than the new application date, which could result in delays, potential loss of return allowance, and potential loss of cost eligibility.

To avoid this issue, the application process allows the applicant to apply "in the alternative", meaning that if the application for an expansion is denied, the application will be treated as an application for a new Project, with the same effective date. The Department will consult with the applicant prior to this review. (See section 2.1.1.2.2 "Application in the Alternative")

3.3.3.2 Project Ownership

OSR Project applications must identify all leases and lease owners for the proposed OSR Project.

When there is more than one lessee, the application must identify each lessee's equity percentage. If the application is made by the OSR Project lessee's designee or there is more than one lessee, documentation authorizing the designee to apply must be submitted together with the application. A letter from each OSR Project lessee clearly authorizing or consenting to the application being made by the designee is sufficient.

3.3.3.3 Project Identification

OASIS requires applicants to provide a Project name, Project operator and contact person. If the application is for an OSR Project amendment, the OSR Project approval number should be included as well.

The OSR Project contact person is the individual to whom the Department will direct all correspondence and inquiries regarding the OSR Project.

OASIS will require the following details about the designated contact person:

- name

- title
- company
- mailing address
- courier address (as appropriate)
- telephone number and area code
- fax number and area code
- e-mail address.

The OSR Project operator is responsible for notifying the Department whenever contact-related details change.

3.3.3.4 Project Overview

OASIS asks applicants to provide a summary of the OSR Project's history and development intentions. The summary should include the following information:

- the dates when lands and leases were acquired
- a proposed effective date for the OSR Project
- the locations of the first wells on the OSR Project site and the dates they were drilled
- a description of the lands and facilities included within the proposed OSR Project
- a history of OSR Project operations / development work completed to point of application
- a description of costs incurred to date
- an outline of the expected OSR Project production, operations, and future development plans and investment.
- annual production to date and future production expectations
- a description of any cost or revenue NAL transactions with other Projects or affiliates.
- an overview of Project engineering systems
- other relevant details

Applications pertaining to OSR Project amendments must describe the relationship between the proposed amendment and the existing OSR Project. Applications that do not provide sufficient information may be rejected.

3.3.3.5 Project Description

> The Department reviews OSR Project applications on the basis of information provided by the applicant in this section.
>
> Errors in the OSR Project description may result in errors such as lands and facilities being excluded from the OSR Project description issued as part of the OSR Project approval order. Costs may be disallowed as a result.

The OSR Project description should include details about the following relevant information:

- AER applications and approvals
- lands and leases,
- wells
- Project operations
- facilities and other assets.

A **map or aerial photo** showing the OSR Project development area and facilities must also be included.

3.3.3.5.1 Alberta Energy Regulator Approvals

The production schemes or operations of a proposed OSR Project must all be approved by the AER. An OSR Project application can include all or a part of one or more AER approvals.

Copies of all relevant AER applications and approvals must be filed with the Department as part of the application for OSR Project approval. A description of each AER-approved OSR Project component, with approval attached, should also be included.

If the approvals include specific terms or conditions required by the AER, this should be brought to the Department's attention. Related applications and approvals for separate facilities (e.g. batteries, processing plants, cleaning and treating plants, upgraders, sand disposal facilities, pipelines, etc.) also must be included.

The Department may require copies of supporting regulatory applications (such as relevant sections of an environmental impact assessment) and approvals to complete the review of any specific application regarding an OSR Project.

All required AER approvals must be in place before an OSR Project application will be accepted.

3.3.3.5.2 Lands and Leases

OASIS will ask applicants to provide the following information about the OSR Project development area:

3.3.3.5.3 Project Lands

- legal land descriptions (LSD, Section, Township, Range and Meridian) that define the surface areas to be included in the OSR Project,
- a map showing the area and OSR Project wells, facilities and infrastructure must be included.

3.3.3.5.4 Project Leases

- the lease number and lease description for all oil sands agreements to be included within the OSR Project
- the subsurface strata, Zone Designations/Deeper Rights Reversion Zone Designations, and deposits from which oil sands products will be recovered
- an oil sands lease cannot be approved as part of an OSR Project unless the development of the leased area, or any part of it, has been approved by the AER.

3.3.3.5.5 Project Operations

Applicants should provide:

- a description of proposed Project operations
- the recovery methods and technology that will be used
- a listing of the kinds of oil sands products that will be recovered or obtained
- a listing and description of the wells to be included if the production is solely from specified wells
- a description of the integrated project including integrated shared operations and the integrated upgrader, if the proposed project is part of an integrated project
- a listing and description of non-arm's length transactions expected to occur for the supply of any assets, goods or services for the OSR Project, or for the supply of any assets, goods or services produced or generated other than for the purposes of the OSR Project
- a listing of engineering systems and methodologies for allocating costs
- information on development plans, future production profile or anticipated production profile
- information regarding recoverable reserves estimates and reservoir properties with a net pay map for the entire area

- process flow diagrams indicating the design capacity of all major components.
- listing of all royalty calculation points for the Project, including the physical location, the types of measurement devices used at the RCP, and the expected accuracy of measurement of Project substances at the RCP.

3.3.3.5.6 **Wells** Applicants must provide the name, unique well identifier and finished drilling date for all wells included in the proposed Project.

An application cannot be made for a project unless the proposed Project includes at least two wells for the recovery of bitumen.

3.3.3.5.7 **Facilities and Other Capital Assets and Engineering Systems** Applicants must provide the following information about each facility, asset and engineering system required to produce the proposed oil sands products:

- a description of the assets proposed to be included in the OSR Project, including whether any such assets located other than on or off OSR Project lands.
- a Class 3 estimate if the application for a Project includes new processing plant[5](s) or modifications to the existing one(s) with estimated capital cost of $50 million or more.
- the function of the asset or facility.
- the location of the asset or facility.
- a list of the engineering systems that are identifiable in the Project.
- a list of assets or engineering systems that provide service to other royalty or non- royalty Projects with detailed description of the asset or engineering system.
- a proposed cost allocation methodology for each shared asset with necessary map or engineering diagrams including design capacities, throughputs and flow rates, if applicable.
- the proposed allocation of costs based on the use by Project operations or integrated shared operations and integrated upgrader, if any.
- each lessee’s specific equity share of any capital assets material to OSR Project operations.

[5] “processing plant” as defined in the Oil Sands Conservation Act means “(i) a facility for obtaining crude bitumen from oil sands that have been recovered, (ii) a facility for obtaining oil sands products from oil sands, crude bitumen, de-asphalted bitumen or synthetic crude oil, or (iii) a stand-alone gas fractionating plant for obtaining methane, ethane, propane, butane or other similar light hydrocarbons from oil sands products”. A facility does not include wells, or things over which the Alberta Energy Regulator has no jurisdiction, such as roads, airstrips, camps, bridges, etc.

- a description of all other assets that are expected to be of material relevance to OSR Project operations, including any measured use assets that support the project but are not included in the Project.
- a description of the level of use of the assets for OSR Project and non-project uses over the expected life of the asset.
- the facility name and identification code, if available.
- the appropriate AER approvals or permits.
- a description of all key measurement devices expected to be used for the project including measurement devices for measured use systems and for measuring project substances at the royalty calculation point.
- a description should include the physical description of the measurement devices, their physical location, the expected accuracy of the devices, and any other important information about the measurement devices.

In determining the proportion of assets which may be included in the Project or the allocation of costs regarding measured use assets and other engineering systems Schedules 2 and 3 of the OSACR must be used where applicable.

All shared or co-owned facilities and all facilities and assets located off project lands must be clearly identified. Each owner's equity share must be specified.

Note

> If an asset or facility is not clearly identified by the OSR Project applicant, it will not be included in the OSR Project description that forms a part of an OSR Project approval order. Unless the asset or facility is included in the OSR Project description, its costs are not allowed as OSR Project costs and cannot be considered in calculating the OSR Project PNCB.

3.3.3.5.8 **Financial Information**

Financial information submitted by an OSR Project applicant is treated as confidential in accordance with section 50 of the Act, section 26.1 of the MMAR, and with the Freedom of Information and Protection of Privacy Act, RSA 1994, c. F-18.5.

Any OSR Project applications not including financial information will be considered incomplete.

All financial information is subject to verification by the Department's auditors.

OSR Project costs and revenues must be itemized on standard PNCB forms and supported by authorizations for expenditure (AFEs) or comparable budgetary approval documents and invoice numbers. Relevant AFEs must be submitted as part of the OSR Project application.

The PNCB form is available for download from the Department's website in Excel or PDF format (from the Department's website (http://www.energy.alberta.ca/), navigate to "Oil Sands," then "Forms."), however all submissions of the PNCB form must be made in Excel format. An authorization for expenditure (AFE) or comparable budgetary approval document must be included with each form.

The following PNCB forms must be submitted for each OSR Project or amendment application:

- Calculation of Prior Net Cumulative Balance: Summary
    - This form summarizes the costs and revenues for the appropriate Period(s). Applicants must provide information for all the categories included on this form.
- Prior Net Cumulative Balance: Capital and Operating Cost Detail
    - A cost detail form must be completed for each Period reported on the PNCB summary.
    - For all capital assets, cross-reference the corresponding AFE number on a separate sheet. The categories included on the cost detail forms are intended as examples. Project applicants may substitute categories that reflect their particular operations for those in the example.
    - Provide proposed allocations between OSR Project and non-project assets (if applicable).
- Prior Net Cumulative Balance: Revenue Detail
    - A revenue detail form must be completed for each Period reported on the summary form. Applicants must provide information for all the categories included on this form.
    - All volumes from well events prior to the effective date must be included in the amounts reported.
    - Amounts that would be classified as other net proceeds, if they were received after the Project's effective date must be included.

The OSR Project operator must also include an electronic transaction listing of capital and operating expenses claimed that reconciles with the total amounts claimed on the PNCB. This file should include sufficient information to allow the Department's auditors to trace a transaction to its supporting documentation and should include the name of the vendor, the invoice number, invoice date, a description of the transaction, the AFE number, account number, account description, cheque number/payment date, and any other information necessary to identify the nature and purpose of the transaction.

3.3.3.5.9 **Economic Evaluation Data**

With the exception of administrative amendments, all OSR Project applications for proposed projects must be accompanied by Economic Evaluation Data except for those applications that are administrative in nature. Any application not including this data is considered incomplete.

The Department requires information on production, prices (in real dollars) and costs (in real dollars) based on the operator's best estimate. The Department, however, reserves the right to adjust any or all of the data provided while doing its internal review/analysis, and to ask for supporting data/clarification for the economic case(s) provided.

All information submitted by an OSR Project applicant is kept confidential in accordance with section 50 of the Act and with the *Freedom of Information and Protection of Privacy Act*, RSA 1994, c. F-18.5.

OSRR09 requires the Minister to consider the economics of all proposed projects and proposed amendments to OSR Projects.

The following Economic Evaluation Data forms may be required:

1) New Project Applications or Existing Projects
   - Economic data relating to a “New” Project or to a “Current” approved OSR Project
2) Project Application Amendment (not required for “New” Project applications)
   - Incremental economic data - assuming the OSR Project would be a stand-alone OSR Project for royalty purposes
   - Data relating to the incremental case and wells only
3) Amended Project (not required for “New” Project applications)
   - Data relating to the combined Project: OSR approved Project plus the Amendment
4) Project Review Summary
   - Input from the above three Economic Evaluation Data forms will be summarized on the Project Review Summary report.
   - All necessary header information must be completed such as the: AER approval number, OSR Project number, Project Name, Project Operator Name and ID and Current Application Proposed Effective Date: Year/Month/Day.

Note

> Not all amendments to OSR Projects require the submission of Economic Evaluation Data. For example: an administrative change, such as a change of operator, does not require economic data.

Annual data must be provided for the full life cycle of the OSR Project. To facilitate the economic evaluation of proposed Projects (for each case required) the applicant must report data for the following data fields. All other fields on this form are calculated fields.

PROJECT IDENTIFICATION SECTION

- AER approval number if the application is for a new or existing OSR Project, OSR Project application amendments and/or amended OSR Project.
- Existing OSR Project number.
- Project name.
- Project Operator.
- Operator ID for Royalty.
- Current Application Proposed Effective Date. Note: Overwrite the date currently in the cell, as this is just a placeholder. The first year in the table below will be equal to the year of the current application proposed effective date.
- Project region (e.g., Cold Lake, Athabasca, or Peace River).
- Project recovery technology.
- Notes - provide any additional information/ clarification if needed.
    - this field is “symbol” sensitive, use text and numeric values only.

GENERAL INFORMATION SECTION

- First production date (enter year)
    - for a New Project Application or Existing Project, enter the expected/original start date of production.
    - for a Project Application Amendment, enter the start date of incremental production.
    - for an Amended Project, enter the original start date of production.
- Last production year (economic cut-off) (enter year)
    - for a New Project Application or Existing Project, enter the last date of the production.
    - for a Project Application Amendment, enter the last date of incremental production.
    - for an Amended Project, enter the expected last date of the Amended OSR Project production.
- Data in real dollars as of (enter year) - enter the year the real dollars refer to.

- Return allowance rate (percentage: a range between 0.00-10.00% is required).
- Opening unrecovered balance/PNCB – enter amount in dollars
  - for a New Project Application or Existing Project, enter the PNCB or opening unrecovered balance.
  - for a Project Application Amendment, enter the PNCB.
  - for an OSR Amended Project, enter the opening unrecovered balance for the Amended Project.
- Density - provide cleaned crude bitumen density pre-blend in kg/m3 (a range between 800.0 and 1100.0 is required).
- Sulphur – provide cleaned crude bitumen sulphur content in wt% (a range between 0.00% – 10.00% is required).
- TAN – provide TAN of cleaned crude bitumen in mgKOH/g - (a range between 0.00 – 5.00 is required).
- Viscosity – provide bitumen viscosity in centipoise at the reservoir temperature in degrees Celsius (°C).
- Diluent ratio - (a range between 0.00 – 1.00 is required).
- Type of diluent, e.g. condensate, SCO, etc. (30 character limit)
- Stream – provide full name of stream(s), e.g. Wabasca Heavy, Cold Lake Blend, etc.

Notes - provide any additional information/ clarification if needed.

  - this field is “symbol” sensitive, use text and numeric values only.

TABLE DETAILS

- Year
  - Start at year that matches previously reported PNCB number. If, for example, PNCB was reported in the application to the Department for the Period ending October 2015, then the data in this table should start as of November 2015 (partial-year) and then full years thereafter.
- Production
  - Bitumen production volumes (m^3) from proven (1P) or proven and probable (2P) reserves for the year.(refer to IB 2015-07)
- Bitumen production volumes (m^3) from best estimate contingent resources (2C) for the year.
- Steam injection volumes (m^3) for the year. Field not applicable for mining projects.
- Number of new production wells for the year. Field not applicable for mining projects.

- Number of abandoned production wells for the year. Field not applicable for mining projects.
- Number of new injection wells for the year. Field not applicable for mining projects.
- Number of abandoned injection wells for the year. Field not applicable for mining projects.
- Bitumen price (C$/$m^3$).
- WTI (West Texas Intermediate) price (C$/bbl).
- Natural gas price (C$/GJ).
- Net gas production and consumption (i.e., gas produced less consumed) (GJ) - enter gas consumption as negative.
- Non-gas variable operating expenditure (Opex) (C$/$m^3$).
- Fixed Opex – reported in dollars per year (C$/yr)
- Sustaining Capital expenditures (C$/yr) – Sustaining capex for wells
- Sustaining Capital expenditures (C$/yr) – Sustaining capex for facilities.
- Strategic Capital expenditures (C$/yr) – Strategic capex for wells.
- Strategic Capital expenditures (C$/yr) – Strategic capex for facilities.
- Abandonment Capital expenditures (C$/yr) – well abandonment costs.
- Abandonment Capital expenditures (C$/yr) – facility abandonment costs.
- Abandonment Capital expenditures (C$/yr) – reclamation costs.
- Other net proceeds (C$/yr).

NOTE: All dollar values to be expressed in real terms. Unless stated otherwise, all input data into the Client Submission form is stored and displayed to 2 decimal places. The following is a list of exceptions and the corresponding number of decimal places that they will be displayed and stored.

<u>Do not require decimal places</u>

- No. of New Production Wells
- No. of Abandoned Production Wells
- No. of New Injection Wells
- No. of Abandoned Injection Wells
- Opening Unrecovered Balance
- Gross Revenue
- Crown Royalty Based on Gross Revenue
- Crown Royalty Based on Net Revenue

- Crown Royalty Payable
- Unrecovered Balance Before Return Allowance
- Unrecovered Balance After Return Allowance

1 decimal place

- Proved (1P) or Proved + Probable (2P) Bitumen Production Volumes (m^3)
- 2C Bitumen Production Volumes (m^3)
- Steam Injection Volumes (m^3)

5 decimal places

- Gross Royalty Rate
- Net Royalty Rate

The Economic Evaluations Data form is available for download from the in Excel or PDF format (From the Department's website (http://www.energy.alberta.ca/), navigate to "Oil Sands," then to "Forms", however all submissions of the Economic Evaluations form must be made through the secure web application Electronic Transfer System (ETS) in Excel format.

3.3.3.5.10 Signatures

Applications for approval of OSR Projects must be signed by an authorized officer who represents the OSR Project lessee or the lessee's designee and by the individual who completed the application.

These signatures:

- verify the information included in the application is accurate,
- authorize the Department to audit the information and to access additional OSR Project records, if required,
- confirm the applicant accepts responsibility for reporting OSR Project changes to the Department, and,
- confirm the applicant's willingness to comply with the provisions of the OSRR09.

3.4 The Approval Process

3.4.1 Pre-Screening Process

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 5 and 10

Applications which do not fully satisfy the requirements of Section 10(2) or 10(4) may be deemed incomplete and rejected, under Section 10(6)(a) of OSRR09.

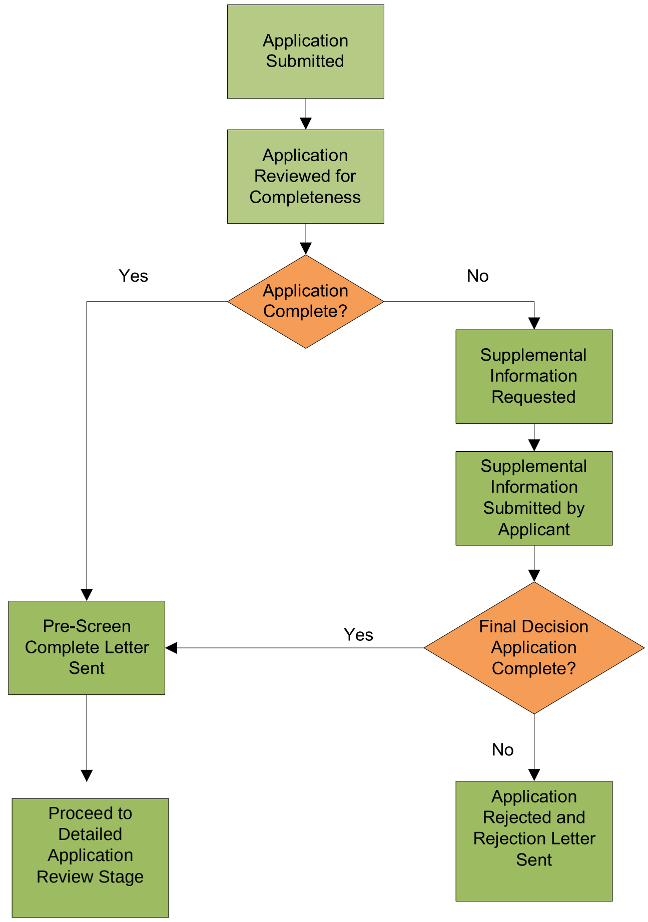
The Project Engineering and Approvals Unit will assess applications and provide Project operators with an opportunity to remedy any deficiencies in their applications before rejecting them. The application pre-screening process and timelines are as follows:

- The applicant submits an application that complies with sections 5 and 10 of the OSRR09.
- The Department begins the pre-screen review process upon receipt of the application. The pre-screen review process should take ten business days.
- If the application is considered to be complete, the applicant would be notified with a pre-screen completion letter. If the application is determined to be incomplete, the Department will notify the applicant of the application deficiencies that must be rectified, and would provide ten business days for the applicant to respond and provide the missing information.
- On receipt of the supplemental information, the Department will determine if the application is complete. If the application is complete, a pre-screen completion letter will be sent to the applicant and the detailed review of the application will commence. If all the requested information is not provided by this time, then the application will be rejected as incomplete, pursuant to subsections 5(4) and 10(6) of the OSRR09, and written notice provided to the applicant.
- If an application is rejected as incomplete and the application is re-submitted the timeline noted above will begin again.

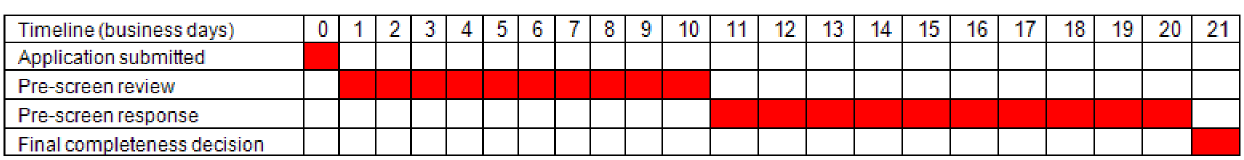
Project Application - Common Questions and Answer

Refer to Oil Sands Royalty Information Bulletin 2010-13

3.4.1.1 Pre-screen Process Flowchart



3.4.1.2 Pre-screen Process Timeline



3.4.2 Departmental Review

When an OSR Project application is received, a Departmental review will be conducted to ensure that:

- the application is complete
- all required attachments have been included

- the required signatures are present
- the proposed OSR Project meets the requirements of the Regulation
- If the application is in good order, it is assigned a provisional Project approval order number and a provisional effective date.
- The application is then reviewed by the Oil Sands Operations, Project Engineering & Approvals Unit. This unit evaluates the application in accordance with the provisions of the OSRR and prepares the Ministerial Order, if the application is approved. The Ministerial Order contains the description of the Royalty Project (e.g. allowed leases, lands, activities, facilities, wells, etc.)

3.4.3 Project Approval: The Ministerial Order and Cost Allocation Order

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 11 and 11.1

A Ministerial Order is signed by an authorized delegate of the Minister signifying the approval of an application. The original Ministerial Order and related attachments are kept on file with the Department. Pertinent information is entered into the Department's royalty information system.

The Ministerial Order provides approval and legal authority for an OSR Project. An appendix to the Ministerial Order:

- specifies the Project approval order number.
- describes the Project, its facilities, lands, leases, assets, and operations (inclusions and exclusions).
- specifies the Project's effective date.
- specifies the PNCB of the Project, and
- outlines any terms and conditions to which the approval is made subject to, such as: the maximum production capacity (MPC) or the maximum period of time (MPT) for expansion of the Project's production capacity if the Minister has established such parameters for the Project.
- must specify the cumulative cost and cumulative revenue for amalgamated Projects.

When a Ministerial Order is issued, the Minister may also issue a cost allocation order specifying measured use assets that support the Project, the proportion, part or proportion of a part of other capital assets or engineering systems that are part of the Project, and the cost allocation methodology for the Project. The cost allocation order is deemed to be part of the Ministerial Order.

Confidentiality

> Ministerial Orders are not public documents as the information contained is confidential.

3.4.4 Project Approval Process Timeline

The evaluation process involves engineering analysis, economic analysis, PNCB audits/reviews, etc. The Department makes every effort to expedite the exchange of information with OSR Project applicants. The Department requires the cooperation of applicants in responding to information requests in a timely fashion.

Note

> Section 13 of the OSRR09 states the effective date cannot be earlier than the first day of the month that precedes by 9 months the month in which the Project or Project amendment is approved by the Minister.

3.5 Project Revocation

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 12 and section 17

Lessees of a Project may apply for the revocation of all or part of their Project Approval. The Minister may (by order) revoke (either entirely or partially) an OSR Project approval, Prior Approval, or an order made under Section 12 of the OSRR09.

The Minister may use these revocation powers if:

- the lessees of the Project have applied for revocation, and the overall impact the revocation of the approval will have on royalty payable to the Crown is acceptable to the Minister,
- the Minister is satisfied that fraud, or misrepresentation attributable to neglect, carelessness or willful default has occurred in the filing or submission of the application for the approval or of any other information in connection with the application, or in the creation, maintaining or concealment of a record subject to examination relating to the application, order or Project,
- a requirement set out in the application (section 1) ceases to be satisfied in relation to the Project,
- any term or condition of the approval or order has been breached and, if the breach is capable of rectification, the breach has not been rectified within the Period of time specified in a notice given to the operator of the Project informing the operator of the breach,
- the operator or a lessee of the Project has materially or repeatedly breached any provision of the Act, of any regulations under the Act or of any enactment referred to in section 6(1)(b) (measurement),
- the Project or part of the Project has been substantially suspended, sold, transferred, abandoned, or otherwise disposed of,
- any of the agreements granting the right to recover oil sands or oil sands products from the development area of the Project have expired or been cancelled, sold, transferred or otherwise disposed of.

The Department will:

- provide written notice at least 30 days or at least the number of days agreed to by the operator of the Project if the operator has agreed to a shorter time period before revoking an approval or part of an approval or an order or part of an order, to the operator of the Project of the Minister's intention to revoke the approval or order,
- notify the operator of the Project of the revocation of any such approval or order,
- notify the lessees of the revocation of an approval, or of the Minister's refusal to revoke an approval, in the case of a revocation requested by the lessees,
- the revocation order may include any terms and conditions to which the order is subject, and the effective date of the order.
- the lessees of the agreement shall comply with any terms and conditions in the order affecting the revocation.

3.5.1 Indicators of Project Suspension or Abandonment

To determine whether a Project or part of a Project is substantially suspended or abandoned, the Department may look at indicators, including, but not limited to the following:

<table>
<tr><th>Indicator</th><th>Description</th></tr>
<tr><td rowspan="2">Project Spending Changes</td><td>Substantial decrease in capital spending or operating costs (relative to “normal” Project costs that are required to build the project or continue normal operations).</td></tr>
<tr><td>Increase in some specific costs that indicate reduction or cessation of normal activity (i.e. safe mode costs, cancellation costs, abandonment, reclamation, or remediation costs).</td></tr>
<tr><td>Project Staff Changes</td><td>Significant reduction in project staff.</td></tr>
<tr><td>Changes in Production</td><td>Production falls to zero or a significant reduction in project production (this would only apply for active producing projects, not projects or phases under construction. So typically it would not apply for assessing “substantially suspended” in a PNCB).</td></tr>
<tr><td>Significant reduction of costs over at least 3 months</td><td>For example: Significant operating costs reduction.</td></tr>
<tr><td rowspan="2">Public Announcements</td><td>An announcement that the project is suspended or delayed.</td></tr>
<tr><td>A public indication that the project is no longer fully sanctioned by the company – i.e. an indication that a decision will be made in the future before the project proceeds.</td></tr>
</table>

Indicator	Description
Significant Change to the Project	If the overall project changes and the new plan is no longer the same as that considered in the original OSR approval.
	In the case of a PNCB and "substantially suspended", if there were significant changes to the overall project concept during the course of the review or during the PNCB period.
	Any significant decrease or cessation of project development activities at the project site.
Cancellations	Cancelled contracts.
	Cancelled delivery of major project assets or long lead time assets.
	Sale of any major project assets.
Out of Business or Sale of Project	Result in substantial change in project.

These indicators will trigger an investigation from the department to confirm a Project's current status but it does not automatically render a Project as suspended or abandoned. The department understands that each Project is different and operates under different circumstances. Also, please note that recent changes to the OSRR09 provide for the mandatory notification of suspension of Project operations, prior to such suspension.

4. Calculating Oil Sands Royalty

Oil Sands Royalty Regulation, 2009 (AR 223/2008), Part 4 Division 1 and 2

OSR Projects pay royalty according to Division 2 of Part 4 of the OSRR09. Under Alberta's OSR regime, royalty is paid in one of two ways. Projects pay a gross revenue royalty during prepay out period and the greater of net revenue and gross revenue royalty during the post payout period.

Non-Project oil sands producers pay royalty according to Division 1 of Part 4 of the OSRR09. The Crown's royalty share from non-Project wells is determined according to the *Petroleum Royalty Regulation, 2009*, if the spud date is before January 1, 2017 and according to the *Petroleum Royalty Regulation, 2017*, if the spud date is on or after January 1, 2017. Royalty is paid in cash based on the unit value calculated for the oil sands products. The Crown's royalty share on oil sands from non-project mining operations is equal to 20% of the oil sands delivered in each month at the boundary of the oil sands lease, valued at the oil sands par price, which is prescribed each month by the Minister.

Note: See section 7.3 - "Reporting Requirements - Non-Project OSR Calculations".

The royalty paid on oil sands and oil sands products shall be free and clear of all deductions.

4.1 The Royalty Calculation Point

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 29, 30 and 31

Royalty payable to the Crown is calculated on the volume of oil sands product that is delivered and measured at the applicable royalty calculation point (RCP).

For an OSR Project, the RCP is usually the point where the product is permanently removed from Project facilities. This is the point at which the Crown's royalty share of the product is determined.

If the oil sands product is processed in a processing plant (not part of the OSR Project) to obtain clean crude bitumen prior to its disposition, then the RCP is at the exit of the processing plant.

If the oil sands product is processed in a processing plant (not part of the OSR Project), and prior to disposition is subsequently blended with diluent to obtain blended bitumen immediately adjacent to or in the same processing plant, the RCP is at the exit of that blending facility.

When an oil sands product passes an OSR Project's RCP, it triggers two events:

1. The Crown's share of the oil sands product at the RCP is determined, and
2. Immediately downstream of the RCP, the Crown's share is transferred to the owner of the lessee's share. Compensation is payable to the Crown in respect of that royalty share at that time.

4.2 Elements of the Royalty Calculation

The royalty calculation for an OSR Project may depend on the following elements:

- OSR Project's opening balance payout status, which is its cumulative costs less its cumulative revenues
- Return allowance for the OSR Project
- OSR Project allowed costs
- OSR Project revenues
- Unit price for each oil sands product

4.2.1 Payout Status

An OSR Project reaches payout when its cumulative revenues first equal or exceed its cumulative costs. At payout, an OSR Project has recovered its costs including a return allowance. A pre-payout Project will pay a gross revenue based royalty. A post-payout Project will pay the greater of a gross revenue or net revenue royalty.

4.2.2 The Return Allowance

Oil Sands Allowed Cost (Ministerial) Regulation (AR 231/2008) - Section 2

All pre-payout Projects are allowed a return allowance on the excess of cumulative costs over cumulative revenue. For post-payout Projects, a return allowance may be claimed if an OSR Project has a net loss for the year. In the case of pre-payout Projects, the amount is calculated monthly; in the case of post-payout Projects, the amount is calculated annually.

The return allowance is set by the Long Term Bond Rate (LTBR), which is the calculated rate of return on long-term Canada bonds, as published weekly by the Bank of Canada. The legislative authority for the return allowance is provided by section 2 of the OSACR.

The return allowance is intended to represent a risk-free return on the developer's investment.

For pre-payout Projects, the monthly return allowance rate (mr) is the relevant one. It is calculated as:

$$mr = (1+LTBR)^{1/12} - 1, \text{ where}$$

LTBR is the simple average of the LTBRs reported for the Wednesdays of the preceding month.

For post-payout Projects, the return allowance rate for a Period is the simple average of the LTBRs published for the last Wednesday of each month in the Period.

The Long-Term Bond Rate (LTBR)

The LTBR is published weekly by the Bank of Canada on Wednesday and can be accessed on the Bank of Canada website at: http://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/ or on the Department's website (navigating through the "Oil Sands" and "Oil Sands Royalties" section and choosing "Rates of Return").

4.2.2.1 The Return Allowance for Pre-Payout Projects

Oil Sands Allowed Cost (Ministerial) Regulation (AR 231/2008) - Section 15(3)

For pre-payout Projects, the return allowance is calculated monthly by multiplying the Project's net cumulative balance at the end of the month (the Project's cumulative costs less cumulative revenues) by the return allowance rate for the month. This return allowance is an allowed cost in the following month. Together with the revenues and other allowed costs in that month, it is included in the calculation of that month's cumulative balance.

The return allowance for pre-payout Projects is reported once a year, on the End of Period Statement (EOPS).

Project operators use the pre-payout Project, EOPS "Return Allowance" PRE-4 form, to report the return allowance for the Period (From the Department's Oil Sands website, navigate to "Oil Sands," then "Forms.")

4.2.2.2 The Return Allowance for Post-Payout Projects

Oil Sands Allowed Cost (Ministerial) Regulation (AR 231/2008) - Section 15(4)

For post-payout Projects, a return allowance is provided only when the Project has a net loss at the end of a Period.

1. If the Project ends a Period in a net loss position and also incurred a net loss in the preceding Period, a return allowance is provided over the full Period (365 days). The return allowance is the product of the return allowance rate for the Period multiplied by the net loss for the Period.
2. If a Project incurs a net loss in a post-payout Period, but a net loss was not incurred in the preceding post-payout Period, a return allowance is provided based on half the Period's net loss. The return allowance is the product of the return allowance rate for the Period multiplied by (183/365), multiplied by the net loss for the Period.
3. If a Project attains payout in a calendar year, and then incurs a net loss in its first post-payout Period, or in any other case where the post-payout Period comprises less than a full calendar year, the return allowance for the Period is adjusted to reflect the proportion of the full calendar year that the Period represents.

   For example, assume a Project pays out in June of a year. Its first post-payout Period then begins on June 1st of that year, and will include 7 months (June – December) rather than being a full calendar year. If the project incurs a net loss in that Period, its return allowance in respect of that year will be calculated as: the product of the return allowance rate for the period multiplied by (183/365), multiplied by the net loss for the Period, multiplied by (7/12). This last adjustment corrects for the fact that the return allowance rate for the Period (the simple average of the LTBRs for the seven months in the Period) is expressed as an annual rate, whereas the loss only applies to a seven-month Period. The (183/365) factor remains because there was no preceding post-payout Period in which a loss was incurred – there was no preceding post-payout Period at all.

4. If the Project ends the Period in a positive net revenue position, no return allowance is allowed, in respect of that post-payout Period, regardless of the net revenue position at the start of the Period or in the intervening months.

The return allowance for post-payout Projects is reported annually on the EOPS.

Project operators use the post-payout, EOPS "Return Allowance" PST-6 form, to report the return allowance for the Period. (From the Department's Oil Sands website, navigate to "Oil Sands," then "Forms.")

4.2.2.3 The Return Allowance for Suspended or Abandoned Projects

Oil Sands Allowed Costs (Ministerial) Regulation (AR 231/2008) - Section 15(6)

The return allowance is not an allowed cost of an OSR Project if the Minister has notified the operator of the Project that the Minister is of the opinion that Project operations have been or are substantially suspended or abandoned for a Period.

The Minister may make this determination on a retroactive basis, if the Minister was not informed of the substantial suspension or abandonment of operations in advance. See Section 3.5 for indicators of project suspension or abandonment.

4.2.3 Allowed Costs

Oil Sands Allowed Costs (Ministerial) Regulation, (AR 231/2008) Section 3, 4 and 5

Allowed costs are costs incurred by or on behalf of the lessee or operator of a Project to carry out Project operations, which are reasonable and adequately documented.

4.2.3.1 Types of Allowed Costs

Allowed costs must be either:

- specifically included costs of an OSR Project
- fundamental costs of an OSR Project
- discretionary allowed costs of a OSR Project

Specifically included costs are costs described in Schedule 1.1 for Project operations starting January 01, 2017 onwards and Schedule 1 for Project operations starting from January 01, 2009 to December 31, 2016 appended to the OSACR.

Fundamental costs are costs incurred directly to obtain, process, transport or market oil sands products; to reclaim or abandon Project lands; or to comply with applicable environmental laws. Fundamental costs do not include corporate overhead, costs incurred on non-project lands, or costs of a Project expansion prior to its effective date.

Discretionary allowed costs are costs which have been approved by the Minister, upon application by the operator, as allowed costs of the OSR Project. Applications for discretionary allowed costs may be prospective or retrospective. The Minister may establish a term for the approval of a discretionary allowed cost and impose conditions to which the approval is subject. The Minister may revoke his approval if the conditions are not met.

An operator may request an advance ruling with respect to a discretionary allowed cost. Project owners or operators must submit a written request each time an advance ruling is required. (Unless otherwise directed by the Minister, Project owners or operators do not need to resubmit a written request for the same business issue or transaction.) The Department will only issue an advance ruling if the business issue or transaction is one that applies in an actual or a proposed OSR project (see section 8 "Advanced Rulings").

4.2.3.2 Reasonableness

A cost incurred must be reasonable, in both amount and purpose, in relation to the circumstances under which it is incurred. Reasonableness will be assessed on a case-by-case basis.

4.2.3.3 When Costs are Considered to be Incurred

Costs are considered to be incurred in the following circumstances:

- In the month in which the cost is payable, to the extent the amount that is paid in the month in which the cost is payable, to the extent the amount that is paid within 90 days after the cost becomes payable.
- In the month in which the cost is paid (to the extent the amount is not paid within 90 days).
- In the month the services or materials are received, where the costs are in respect of services or materials provided by a lessee, operator, or an affiliate of either and no invoices is provided.
- An allowed cost, which meets the above criteria, is incurred even if it is not reported by the OSR Project operator.

Please refer to Information Bulletin IB 2013-11 Clarification of Arm's Length Costs Incurred and Costs Accrued Under the Generic Royalty Regime

4.2.3.4 Cost Allocation

Oil Sands Allowed Cost (Ministerial) Regulation (A/R 231/2008) – Section 8

When a cost is incurred by a Project operator that is only in part an allowed cost of the Project, the operator must allocate the appropriate portion of the cost to the Project. Any cost allocated to the Project must meet the requirements for allowed costs specified in the OSACR, and be appropriately documented. For example, in the case of an employee (except for managers and executives), part of whose time is devoted to the OSR Project, there should be evidence that the employee was paid, and evidence from records (i.e., timesheets) acceptable to the Minister that a portion of the employee's time was spent on the OSR Project.

The need for cost allocation can arise when:

- A Project is part of an integrated project, and a cost is incurred that is only partially attributable to the royalty project; and
- A Project is not part of an integrated project, but its operator incurs a cost that is also in respect of another royalty Project, or some non-Project operation.

Allocations may be limited in some cases as specified in Schedule 1 and 1.1. The Schedules refer to those costs as "solely dedicated towards providing services to a single project" or "solely dedicated to Project operations" or "solely dedicated to operations of one or more Projects operated by the same operator"

Amendments to the OSACR, which came into effect on January 01, 2017, define and clarify the allocation of costs between/among OSR Projects operated by the same operator and between/among Projects and non-Project operations (operated by the same operator) in terms of salaries, wages, benefits, training, travel, accommodation, relocation and severance (please refer to item 56 and 58 of schedule 1.1 in OSACR).

Amendments to the OSACR, which came into effect on January 1, 2011, define the allocation of costs between Project and non-Project uses.

Projects that are part of integrated projects

Oil Sands Allowed Cost (Ministerial) Regulation (A/R 231/2008) – Section 8.1

For a Project that is part of an integrated project, Schedules 2 and 3 of the OSACR specify the appropriate methodologies for cost allocation. Costs allocated to a Project through an allocation methodology are allowed costs of that Project.

In Schedule 2, the costs of each of the following five engineering systems must be allocated to Project operations, non-Project operations, and Integrated Shared Operations (ISO), according to the direct measurement of their use:

Engineering System	Engineering System Output
Boiler feed water (BFW) treatment system	Actual BFW use in m3
Raw water system	Actual raw water use in m3
Fuel gas system	Actual fuel gas use in gigajoules
Steam generation system	Actual net steam energy use in gigajoules
Electricity transmission	Actual net power use in megawatt system hrs.

The costs of each of the following engineering systems must be allocated among Project, non-Project, and Integrated Shared Operations use according to the design intent of the systems:

System Type	Engineering System Output
Control system	Designed input/output (I/O) channel count
Cooling water system	Designed cooling water demand in m3/hour
Instrument air system	Designed instrument air demands in m3/hour
Fire water system	Designed fire hydrants/monitors flow capacity in m3/hour
Emergency Power	Designed emergency power demand in system MW

The costs of each of the following assets or engineering systems must be allocated among Project, non-Project, and Integrated Shared Operations use according to the proportion of their length located within each area:

System or Asset

Potable water lines, Waste water lines, Sewer lines, Sour water lines, Slop oil lines, Pipe racks

The costs of camps must be allocated according to the number of person-days of accommodation provided to employees (excluding contractors) working on the Project, non-Project operations, and the Integrated Shared Operations , as a proportion of the total number of person-days of accommodation provided.

The cost of airstrips and associated facilities must be allocated in proportion to the number of person-flights by persons working on the Project, non-

Project operations, and the Integrated Shared Operations.

Costs assigned to the Integrated Shared Operations are then allocated between the Project and non-Project operations according to Schedule 3: unless the Minister determines otherwise, in proportion to the total value of energy used by the Project and non-Project operations. For the purpose of valuing that energy use, the Minister may specify the value of the energy sources (fuels and electricity) used in the integrated project.

Where an asset or engineering system is not listed in Schedule 2, or the operator believes that the methodology set out in Schedule 2 is not applicable for sound engineering or economic reasons, the operator can apply to the Minister, and propose an alternative methodology for allocating the costs associated with the asset or engineering system.

The operator, in proposing a cost allocation methodology, must apply one or more of the following methods:

- Head count ratios for costs related to serving personnel, such as cafeterias, catering, and medical services;
- Geographic location for costs related to facilities such as shared parking lots, or roads on Project lands; and
- The capital cost ratio, as specified by the Minister, for costs related to security, fencing, site maintenance, and procurement staff.

The final decision on cost allocation lies with the Minister.

<u>Projects that are not part of integrated projects</u>

Oil Sands Allowed Cost (Ministerial) Regulation (A/R 231/2008) – Section 8.2

Where a cost requires allocation, and the allocation methodology for that cost is specified in Schedule 2, then that allocation methodology must be used, even for Projects that are not part of an integrated project.

If the operator believes that it is not possible to apply the methodology set out in schedule 2, for sound economic or engineering reasons, they can apply to the Minister for an alternative cost allocation methodology.

If the cost allocation is in respect of an asset or service not listed in Schedule 2, the operator can apply to the Minister as to how the allocation should be done. The Minister can approve the operator's application if he is satisfied that it will not expose the Crown to the risk of overstated or unverifiable costs being allocated to the Project as allowed costs.

If the Minister does not accept the operator's proposal, he may specify an appropriate methodology by order.

Ministerial Determination

Oil Sands Allowed Cost (Ministerial) Regulation (A/R 231/2008) – Section 8.3

The Minister can require an operator, by notice, to disclose the methodology, rationale, and documentation supporting a cost allocation.

If the response to such a notice is not complete or sufficient, the Minister may amend the allocation of costs, or even determine that no portion of the cost forms an allowed cost of the Project.

It is important for Project operators to work closely with the Department to ensure cost allocation methodologies are acceptable and clearly specified.

More detailed examples regarding the allocation of costs referred to in Schedule 2 can be found in Appendix J.

4.2.4 Project Revenues

The revenues of an OSR Project are determined by three factors:

- Types of oil sands products that are produced.
- Unit price calculations (which determine the value of those oil sands products).
- Project description, which affects the allowed costs of the OSR Project and so its net revenue.

4.2.4.1 Types of Revenue

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 22 and section 24

Four types of revenues are defined for the purpose of royalty calculation:

- Project revenue
- Gross revenue
- Net revenue
- Other net proceeds

Project revenue (PR) for a month or a Period is the sum of all quantities of oil sands products (derived from a Project's development area and measured at their respective RCPs) multiplied by their respective unit prices

Project Revenue = $\sum$ (Product Volume $\times$ Unit Price)

Gross revenue (GR) for a Project for a month or a Period means its Project revenue less the cost of diluent contained in any blended bitumen at the royalty calculation point included in the calculation of its Project revenue.

Gross Revenue = Project Revenue – Cost of Diluent

Net revenue (NR) is the amount by which Project revenue exceeds allowed costs of the Project less other net proceeds in a Period. (Note: In the calculation of the net revenue the cost of diluent purchased in the Period is an allowed cost.)

Other Net Proceeds (ONP) generally refers to any consideration received or receivable during a month or a Period from the sale, lease, license or other disposition of any substances or assets (excluding oil sands products derived from Project's substances) or technology of the Project.

When net revenue is calculated for a Period the value of ONP is deducted from the allowed costs.

Net Revenue = Project Revenue – (Allowed Costs – Other Net Proceeds)

If ONP exceed the allowed costs in a Period the excess of ONP is carried forward to the next Period. **ONP cannot reduce costs below zero in a Period.**

Note

> When a Project is in pre-payout, ONP becomes part of the cumulative revenue.

Examples of ONP include:

- proceeds from an insurance policy
- proceeds from a litigation settlement or threatened litigation, unless the litigation is against the Crown in respect of amounts paid or payable under OSRR09
- proceeds from the processing of non-Project substances in Project facilities
- revenues from the sale, license or lease of Project technology

4.2.5 Unit Price

Oil Sands Royalty Regulation, 2009(AR 223/2008) section 32

Unit prices are product specific:

> A unit price must be calculated for each oil sands product produced by an OSR Project.

For each oil sands product, unit price is the price used to calculate the value of the Crown's royalty share of that product, at the point it is transferred to the owner of the lessee's share, immediately downstream of the royalty calculation point.

For each oil sands product, unit price for a month or a Period is calculated based on the dispositions of that oil sands product in that month or Period. Sales in a month or a Period determine the unit price at the royalty calculation point in that month or Period. (Note that for a pre-payout Project paying royalty monthly, the relevant calculation Period is the month).

If the oil sands product passing the royalty calculation point is subsequently, prior to being disposed of in a third party disposition, blended with other oil sands products or crude oil, the Minister will direct how to determine the unit price for the oil sands product.

Where the Minister believes the value of the oil sands product is fairly represented by the price of the commingled stream, he may direct that the price of the stream be used as the price of the oil sands product in the calculation of the unit price.

Where an equalization scheme is applied to a blended stream, the Minister may use the equalization scheme to calculate the unit price of an oil sands product contained in that stream.

ADDING DILUENT AFTER THE "ROYALTY CALCULATION POINT" BUT BEFORE ARM'S LENGTH DISPOSITION

Because arm's-length dispositions of an oil sands product are used to value that oil sands product at the royalty calculation point it is important that the product at the point of arm's-length disposition and the product at the royalty calculation point are qualitatively the same.

In some cases a Project may ship (unblended) cleaned crude bitumen or "partially" blended bitumen from its royalty calculation point, to which additional diluent is subsequently added before its arm's-length disposition.

In this case, the product at the royalty calculation point and the product disposed of are not qualitatively similar, and it is not appropriate to value the royalty calculation point product at the disposition value: i.e. it would not be correct to value partly blended bitumen at the royalty calculation point according to the value of blended bitumen disposed of in an arm's-length transaction.

In this situation, where additional diluent is added to the oil sands product after the royalty calculation point and prior to arm's-length disposition, the additional diluent should be deemed to have been added at the royalty calculation point. In this way, the product valued at the royalty calculation point is qualitatively the same as the product disposed of in an arm's-length transaction.

- The cost of diluent added after the royalty calculation point and before arm's length disposition is included in the calculation of Project revenues (both gross and net) the same as diluent added at the royalty calculation point.
- No "hypothetical" charges for transporting the additional diluent volume from the actual point of blending to the deemed blending point at the royalty calculation point are allowed.

Note: Oil Sands Royalty Regulation, 2009(AR 223/2008) section 32(9)

> Royalty is not levied on the value of raw crude bitumen. If raw crude bitumen is disposed of, the unit price will be based on the fair market value of the cleaned crude bitumen that could be obtained from that raw crude bitumen. In determining the unit price, the handling charges will include charges that in the Minister's opinion, would have been incurred to transport the crude bitumen to a place where it could have been processed into cleaned crude bitumen, and the processing charges.

Note: Oil Sands Royalty Regulation, 2009(AR 223/2008) section 32(1)(a)

> It is not uncommon that an operator disposes of their oil sands products to an affiliated marketing company. The marketing company takes the products and sells them to a third party, for example at the U.S. Gulf Coast. The marketing company reports the arm's length sales information at the U.S.

Gulf Coast back to the operator. For royalty purposes, the operator reports arm's length sales at the U.S. Gulf Coast and any transportation costs from their Project to the U.S. Gulf Coast as handling charges. However, marketing costs, brokerage fees or other similar charges are not handling charges in accordance with section 32 (1) (a) of the OSRR09.

4.2.5.1 Third Party Dispositions Equal or Exceed the Third Party Disposition Threshold

Oil Sands Royalty Regulation, 2009(AR 223/2008) section 32(2) and 32(3)

If the percentage of third party dispositions of an oil sands product in a month or a Period, as a proportion of the volume of that product delivered to the royalty calculation point in the month or the Period, equals or exceeds the third party disposition threshold, the unit price calculated based on proceeds from those third party disposition can be used to value the entire volume of that product at the royalty calculation point. The third party disposition threshold, now set at 40%, is prescribed by the Department in its monthly Information Letter (Oil Sands Monthly Royalty Rates and BVM Components). From the Department's website (http://www.energy.alberta.ca/), navigate to "Related Links" and "Information Letter".

In this case, the unit price for a month or a Period is calculated as follows:

$$\text{Unit Price} = \frac{TC - HC}{TD}$$

TC means the total consideration received or receivable for the third party disposition in the Period.

HC means all charges incurred in moving the third party disposition quantities of the oil sands product from the royalty calculation point to the point of disposition. Handling charges typically include pipeline tariffs, terminal and processing charges, and other related fees.

> *Handling charges are not allowed costs, nor are they included in determining the PNCB of a Project or Project expansion. Conversely, allowed costs of a Project cannot also be handling charges.*

Total Dispositions (TD) is the quantity of the oil sands product disposed of in third party disposition during the month or the Period.

4.2.5.2 Third Party Dispositions Do Not Meet the Third Party Disposition Threshold

Oil Sands Royalty Regulation, 2009(AR 223/2008) section 32(4) and 32(5)

If the quantity of an oil sands product disposed of in third party dispositions is less than the third party disposition threshold (40%) in a Period, calculated as above, the proceeds of those third party disposition cannot be used to determine a unit price to apply to all the volumes of that oil sands product.

The quantity of oil sands product disposed of in third party dispositions in a month or a Period is used to value an equal volume of that oil sands product at the royalty calculation point in that month or Period. The remaining volumes of that product at the royalty calculation point must be assigned a fair market value for royalty calculation purposes. If a Project has no third party disposition of an oil sands product in a month or a Period, that product must be entirely valued at the royalty calculation point by the assigned fair market value for that month or Period.

Where the third party dispositions do not meet the third party disposition threshold, the unit price for an oil sands product for a Period is calculated as follows:

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

Where "TC" and "HC" are the total considerations and handling charges related to third party dispositions, defined above in 4.2.5.1 "Third Party Dispositions Equals or Exceed the Third party Disposition Threshold".

"PQ" is the total volume of the oil sands product delivered to the royalty calculation point in the month or the Period.

"NQ" is "PQ" minus "TD" where "TD" is the volume of third party disposition, defined above in 4.2.5.1 "Third Party Dispositions Equals or Exceed the Third party Disposition Threshold". However, if the oil sands product is blended bitumen, "NQ" is the volume of cleaned crude bitumen contained in the volume of blended bitumen. This volume of blended bitumen is determined by subtracting the volume of blended bitumen disposed of in third party transactions in that month or Period from the total volume of blended bitumen delivered at the royalty calculation point in the month or Period.

"CD" is, if the oil sands product is blended bitumen, the cost of diluent contained in the volume of blended bitumen calculated by subtracting the volume of blended bitumen disposed of in third party transactions in that month or Period from the total volume of blended bitumen delivered at the royalty calculation point in the month or the Period. In other words, CD is the cost of diluent in the NAL blended bitumen volume containing the NQ. If the oil sands product is not blended bitumen "CD" is zero.

"P" is the price assigned as the fair market value to the volumes of the oil sands product not valued by the third party disposition, as described above. "P" for a Period is the average of the "Ps" calculated for each month in the Period weighted by the volumes "NQ" for the respective months in the Period.

If the oil sands product is cleaned crude bitumen as defined in Section 1(2) of the OSRR'09, the price representing that fair market value is the Hardisty Bitumen Price for the Project minus the transportation allowance for the

Project, both calculated in accordance with the BVMR.

Where that product is blended bitumen, the value of the clean crude bitumen contained in the blended bitumen is also the Hardisty Bitumen Price for the Project minus the transportation allowance for the Project, both calculated in accordance with the BVMR.

In the case of any other oil sands product, the price is the fair market value as determined by the Minister.

4.2.5.3 Bitumen Valuation Methodology

Oil Sands Royalty Regulation, 2009(AR 223/2008) section 32(6),
Bitumen Valuation Methodology (Ministerial) Regulation section 2 and section 5

The BVMR sets out the rules for valuing cleaned crude bitumen where a fair market value must be determined because volumes disposed of in third party transactions are below the third party disposition threshold (40%).

The BVMR uses a two stage approach to calculating the fair market value of a Project's bitumen:

1. First it determines the value of the Project's bitumen at the Hardisty hub. This value is called the "Hardisty Bitumen Price"
2. Then it calculates a transportation allowance designed to reflect the cost of transporting cleaned crude bitumen from the Project to Hardisty.

By subtracting the transportation allowance from the Hardisty Bitumen Price, we arrive at the value of cleaned crude bitumen at the Project's royalty calculation point.

Note

> Because the transportation allowance is used in the calculation of the value of cleaned crude bitumen at the Project's royalty calculation point, no "handling charges" are included in the BVM calculation.

4.2.5.3.1 **Hardisty Bitumen Value Prior to January 1, 2017**

The BVM values a Project's bitumen at Hardisty as if it were blended with condensate and sold into the Western Canadian Select (WCS) pool.

It establishes the Hardisty Bitumen Price for a Project by assuming the Project's bitumen is blended with a standard condensate stream (CRW) to a density equal to the dilbit component of WCS and delivered into the WCS pool at Hardisty. It is assumed that the Project blend, being of equal density to the WCS dilbit blend, is of equal value.

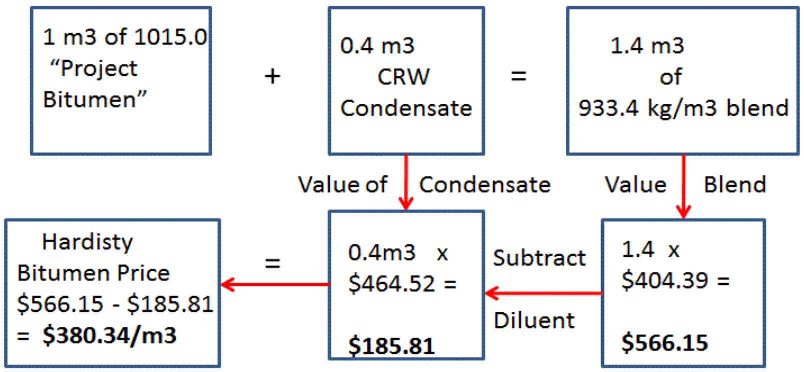
By deducting the value of the included diluent from the value of the volume of dilbit resulting from the blending of one cubic metre (m3) of Project bitumen with enough CRW diluent to match the WCS dilbit density, we get the value of one m^3 of Project bitumen at Hardisty.

Example:

How the BVM Calculates a Project's "Hardisty Bitumen Price"

September 2009 –
WCS Dilbit Density = 933.4 kg/m3
Condensate (CRW) Density = 710.4 kg/m3
Project Bitumen Density = 1015.0 kg/m3
WCS Dilbit Price = C$404.39/m3
CRW Price = C$464.52/m3

From the "blending" model, given these densities and values:



For simplicity, volume shrinkage from blending is ignored. In order to do these calculations each month, a number of data inputs are needed:

- the WCS price for the month in $US/bbl
- the $Cdn/$US Exchange Rate
- the dilbit fraction of the WCS stream
- the WCS Bitumen Synbit premium
- the WCS Blend Density
- Condensate "CRW" Allowance Price
- Condensate "CRW" Density
- (Bitumen Synbit) – (Bitumen Dilbit) Density Blending Difference

From this data we can calculate the density and value of WCS dilbit, and so the value of the Project's dilbit blend and the Project's bitumen.

The Department publishes this data monthly in an Information Letter, which can be downloaded from our website. From the Department's website (http://www.energy.alberta.ca/), navigate to "Related Links" and "Information Letter".

Floor Price Prior to January 1, 2017:

For royalty calculation purposes, before January 01, 2017, a Project's Hardisty Bitumen Price for a month was the greater of the value calculated by the BVM model and the "Floor Price" for the month

In each month, the Floor Price was set as the greater of:

- the average price per m3 of Mexican Maya crude for the month, minus $250, in Canadian dollars, and
- $10/ m3

The floor price was first published in the Department's Information Letter.

4.2.5.3.2 Hardisty Bitumen Price on and after January 1, 2017

Effective January 01, 2017, two significant changes have been made to the Bitumen Valuation Methodology: 1) a quality adjustment and 2) a deduction of Brent minus WTI price differentials, if positive, in the Floor Prices. The rest of the Bitumen Valuation Methodology is unchanged.

Quality Adjustment

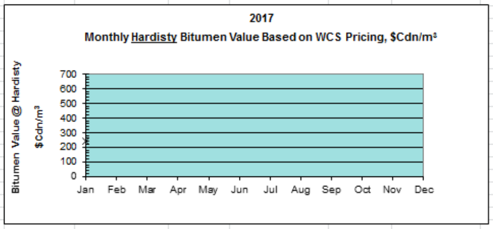
An additional quality adjustment of $4.34171 per m^3 or $0.69 per bbl will be included in the Hardisty Bitumen Price calculation and is meant to consider all quality differentials (TAN, sulfur, solids, etc.). This quality adjustment will be in effect from January 1st, 2017 to December 31st, 2019. The quality adjustment of $0 will begin on January 1st, 2020 pending a review.

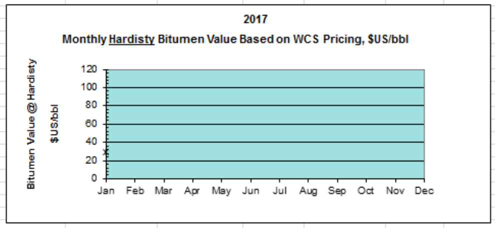
To make the calculation easier a BVM model calculator is available on the Department's website (From the Department's website (http://www.energy.alberta.ca/), navigate to "Oil Sands", "Oil Sands Royalties", and then "Bitumen Valuation Methodology (BVM) Components").

Alberta Oil Sands
Bitumen Valuation Methodology

$4.34171 << *Quality Adjustment, $Cdn/m³*
12 << *(Bitumen_Synbit) - (Bitumen_Dilbit) Density Blending Difference, kg/m³*

2017	Six-measurement [5,6] Rolling Average Bitumen Density kg/m³ @ 15°C	F/X $Cdn/$US	WCS [1] Settlement Price $US/bbl	WCS [2,3] Dilbit Volume Fraction	WCS [2,3] Bitumen Synbit Premium $US/bbl	WCS [2] Blend Density kg/m³ @ 15°C	Condensate [4] "CRW" Allowance Price $Cdn/m³	Condensate [4] "CRW" Density kg/m³ @ 15°C	Royalty Value Bitumen @ Hardisty $Cdn/m³	Royalty Value Bitumen @ Hardisty $US/bbl
Jan	1015.0	1.31909	37.19	0.94	0.07	923.5	433.59	729.5	238.42	28.72
Feb									#N/A	#N/A
Mar									#N/A	#N/A
Apr									#N/A	#N/A
May									#N/A	#N/A
Jun									#N/A	#N/A
Jul									#N/A	#N/A
Aug									#N/A	#N/A
Sep									#N/A	#N/A
Oct									#N/A	#N/A
Nov									#N/A	#N/A
Dec									#N/A	#N/A





Link to official Crown Site http://www.energy.alberta.ca/OilSands/1542.asp

Sources:
1: Effective Sep 09, calculated using the volume weighted average of the "NGX WCS WTI" and "NEI WCS" indices
for "NGX WCS WTI" details contact Natural Gas Exhange Inc. at: www.ngx.com
for "NEI WCS" details contact Net Energy Inc. at: www.ne2.ca
2: Per WCS Stream Founder's Representative - CNRL
3: Four-month rolling average
4: Per Enbridge, distributed by Equalization Steering Committee
5: The bitumen density should be reported to one decimal place as per IB 2014-06
6: The bitumen density reported should be a six-measurement rolling average as per IB 2014-08

This model calculates the Hardisty Bitumen Price for a Project's bitumen using data from the Information Letter that is published every month (navigate to "Our Business", then "Oil Sands", "Legislation and Policies", and then "Information Letters") and the Project's bitumen density. The quality adjustment of $4.34171 per m³ appears in the area highlighted in orange.

Floor Price on and after January 1, 2017

On and after January 01, 2017, for royalty calculation purposes, a Project's Hardisty Bitumen Price for a month is the greater of the value calculated by the model described in section 4.2.5.3.1 and the "Floor Price" for the month.
To reduce unintended triggering of the floor price, the price differential of Brent minus WTI is deducted if that differential is positive. Otherwise a differential of zero is applied.

In each month, the Floor Price is set as the greater of:

- the average price per m3 of Mexican Maya crude for the month, minus $250 minus the greater of the price differential of Brent minus WTI and zero, and
- $10/ m3

The floor price is published in the Department's monthly Information Letter. The floor price will only be relevant in exceptional market circumstances.

4.2.5.3.3 Calculating the Transportation Allowance for a Project's Bitumen Prior to January 1, 2017

The transportation allowance for each Project is calculated based on actual pipeline transportation rates for pipelines connecting the Project with Edmonton or Hardisty. Edmonton and Hardisty are considered to be "the same place" for the purposes of the BVMR.

A pipeline or a series of pipelines, connecting the Project with Edmonton or Hardisty is called a "removal pipeline" of the Project (according to section 5(1)(d) of the *Bitumen Valuation Methodology (Ministerial) Regulation*). Where a Project has more than one removal pipeline, it is the least cost line that is used in the calculation of the transportation allowance for the Project's bitumen.

If a Project is not connected by a removal pipeline to Edmonton or Hardisty (i.e., a Project that trucks bitumen beyond its royalty calculation point, or is connected by pipeline to somewhere other than Edmonton or Hardisty) the Minister will prescribe an appropriate transportation allowance. Any operators who may be in this situation should contact the Manager, Royalty - Royalty and Tenure Operations, (See Appendix G, "Contact Information") Department for further details.

The transportation allowance for a Project is calculated to take into account both:

- the cost of transporting from the Project to Edmonton/Hardisty the volume of blended bitumen that would result from blending the volume of clean crude bitumen delivered at the Project's royalty calculation point with sufficient CRW diluent to match the WCS dilbit density, and
- the cost of transporting that quantity of CRW diluent to the Project.

Note: The actual volumes of oil sands products (dilbit, synbit, synthetic crude) transported on the removal pipeline, and the actual (if any) volume of diluent transported to the Project, are not considered in the calculation of a Project's transportation allowance.

The volumes of blended bitumen and CRW diluent to be used in calculation of a Project's transportation allowance can be calculated from the data found on the "Calculation" page of the BVM model spreadsheet, in the box labelled "From Data Tables". The example below (for bitumen with a density of 1015.0 kg/m^3) will illustrate this calculation.

	From Data Tables	
	Diluent Required Per Unit Volume of Bitumen	BVM Dilbit Blend Volume Generated Per Unit Volume of Bitumen
Jan	0.4972	1.4896
Feb	0.4824	1.4743
Mar	0.4695	1.4609
Apr	0.4728	1.4644
May	0.4391	1.4310
Jun	0.4205	1.4127
Jul	0.4047	1.3969
Aug	0.3941	1.3868
Sep	0.3958	1.3887
Oct	#N/A	#N/A
Nov	#N/A	#N/A
Dec	#N/A	#N/A

For example, in September 2009, the table shows that 0.3958 m^3 of CRW condensate was required to blend 1.0 m^3 of bitumen to a density equal to the BVM dilbit density for that month. This volume is called the “BVM diluent volume” for the Project.

The result of this blending, after taking shrinkage into account, was 1.3887 m^3 of blended bitumen equal in density to the BVM blend. This volume is called the “BVM blend volume” for the Project.

The transportation allowance for the Project is calculated based on the transportation of:

- blended bitumen (the BVM blend volume factor of the Project x NQ) to Edmonton/Hardisty, and
- diluent (the BVM diluent volume factor of the Project x NQ) to the Project.

Note: In a “take or pay” arrangement where zero volumes cross the RCP and are transported in a month during a plant interruption or maintenance or other circumstances, the transportation allowance does not apply and cannot be used as an allowed cost of the Project.

Here, NQ is the volume of clean crude bitumen delivered at the royalty calculation point which must be valued by the BVM. If a Project needed to value 10,000 m^3 of bitumen using the BVM, its transportation allowance in this example would be based on the cost of transporting:

- 1.3887 x 10,000 m^3 = 13,887 m^3 blend to Edmonton / Hardisty, and
- 0.3958 x 10,000 m^3 = 3,958 m^3 diluent to the Project

The cost of transporting these volumes is determined by the transportation rate for the removal pipeline of the Project, and the transportation rate for the diluent pipeline (if one exists) for the Project.

4.2.5.3.4 Examples of Transportation Rate Calculations for Removal and Diluent Pipelines Prior to January 1, 2017

The examples below will illustrate how pipeline transportation rates are calculated to arrive at the transportation allowance for a Project.

In each case, unless otherwise noted, we will assume the same bitumen volume at royalty calculation point (10,000 m^3), calculated blend volume (13,887 m^3), and calculated diluent volume (3,958 m^3) as used in the discussion above.

The “tariff” of a pipeline means the charges for transportation service on the pipeline, where the service is obtained on an arm’s length basis, or the amount determined under Division 2 of Part 2 of the OSACR where the service is obtained on a NAL basis.

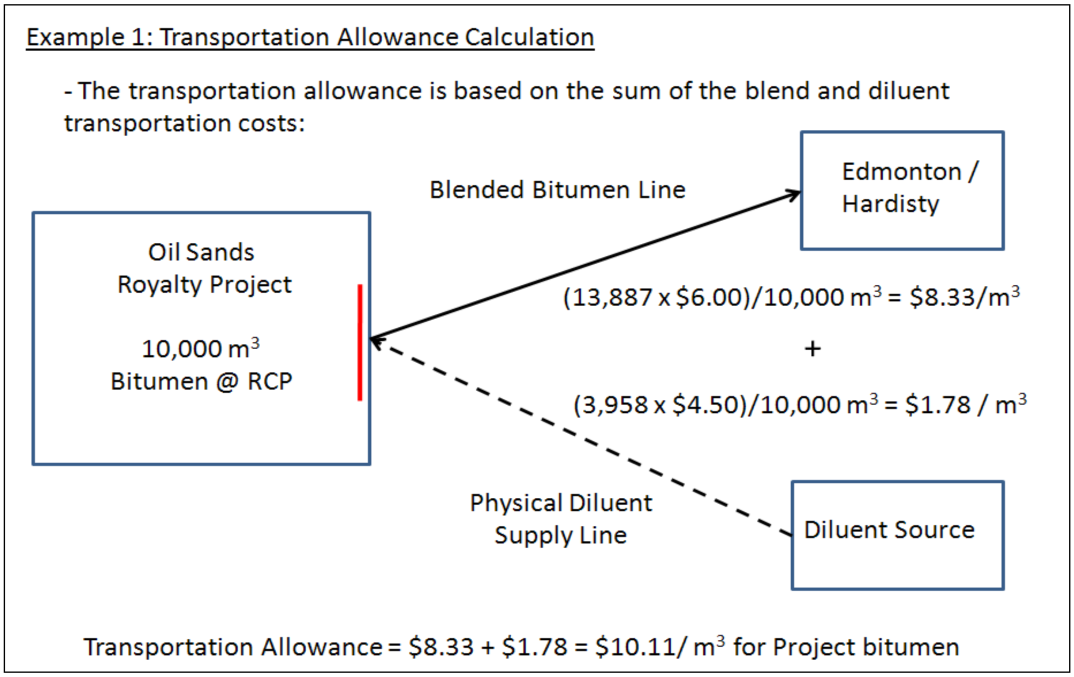
Example 1: A Project with a Blended Bitumen Removal Pipeline and an Actual Diluent Supply Line

This example would represent a Project that “imports” diluent and ships blended bitumen that is disposed of in a non-arms’ length transaction.

Assuming a tariff on the blended bitumen removal line of $6.00/$m^3$ and a tariff on the diluent line of $4.50/$m^3$, the transportation allowance for the Project would be:

[(13,887 x $6.00) + (3,958 x $4.50)] / 10,000 = $10.11/$m^3$ of Project bitumen

This is the amount that would be subtracted from the Project’s Hardisty Bitumen Value to get the price “P” for unit price calculation purposes, as per Section 32 of the OSRR’09: “P” represents the value of the bitumen at the Project’s royalty calculation point.



Example 2: A Project with a Blended Bitumen Removal Pipeline but no Actual (physical) Diluent Supply Line

This example could represent a Project that sourced diluent on site, i.e. from an affiliated or non-affiliated upgrader.

In this case sections 5(3) and 5(4) of the BVMR would apply and the removal pipeline transportation rate calculation would include an allowance for diluent delivery to the Project.

Assuming again a blend tariff of $6.00/m^3, the transportation allowance would be calculated as;

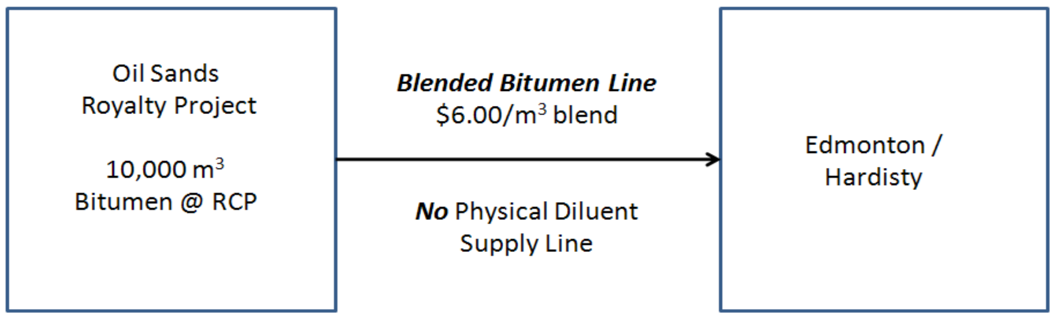
[(13,887 x $6.00) + 0.754 x (3,958 x $6.00)] / 10,000 = $10.12/m^3 of Project bitumen.

In this expression:

- the term (13,887 x $6.00) represents “BRC” from the BVMR - the cost of transporting the blend volume,
- the term (3,958 x $6.00) represents “GRC” from the BVMR – the cost of transporting a volume of blend equal to the required volume of diluent,
- 0.754 is a scaling factor to convert the blend tariff to a tariff for diluent. It is derived from the Enbridge Pipeline tariff,
- in calculating the diluent transportation cost, the 100% load factor tariff is used.

Example 2: Transportation Allowance Calculation

- In the absence of a diluent supply line, the removal pipeline transportation rate calculation includes a proxy for diluent transportation:



Transportation Allowance = {$6.00 x 13,887 + [0.754 x ($6.00 x 3,958)]} / 10,000
= $10.12/$m^3$ of Project Bitumen

Example 3: A Project with an SCO (light crude) Removal Pipeline and no Actual (Physical) Diluent Supply Line

This example could represent a Project which is part of an integrated oil sands Project but pays bitumen royalty.

In this case section 5(6) and 5(7) of the regulation would apply and the removal pipeline transportation rate calculation would again include an allowance for diluent delivery to the Project.

Assuming a $5.00/$m^3$ SCO tariff, the transportation allowance would be calculated as:

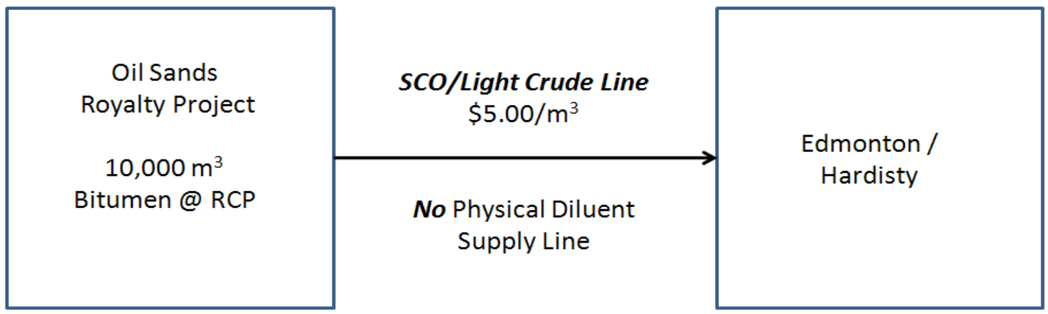
[(13,887 x $5.00 x 1.22) + 0.92 x (3,958 x $5.00)] / 10,000 = $10.29/$m^3$ of Project bitumen

In this expression:

- the term (13,887 x $5.00 x 1.22) represents "TRC" from the Regulation – the cost of transporting the blend volume at the SCO tariff, with that tariff increased by the factor of 1.22 to represent a blend transportation cost as per section 5(7)
- the term (3,958 x $5.00) represents "DRC" from the Regulation – the cost of transporting the diluent at the SCO tariff
- 0.92 is a scaling factor to convert the SCO tariff to a tariff for diluent. It is taken from the Enbridge Pipeline tariff

<u>Example 3: Transportation Allowance Calculation</u>

- In the absence of a diluent supply line, the removal pipeline transportation rate calculation includes a proxy for diluent transportation:



Transportation Allowance = {1.22 X \$5.00 x 13,887 + [0.92 x (\$5.00 x 3,958)]} / 10,000
= \$10.29/m^3 of Project Bitumen

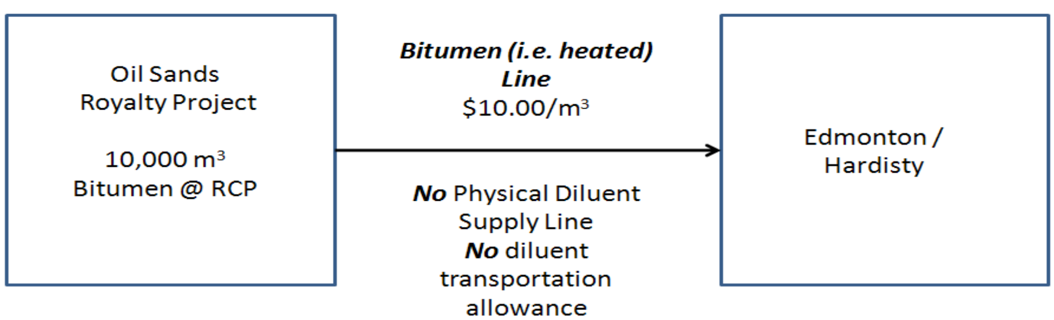
Example 4: A Project with a Clean Crude Bitumen Removal Pipeline

This example could represent a Project which ships bitumen rather than blend, likely through a heated pipeline. In this case Section 5(5) of the BVMR applies.

In this case the transportation allowance is simply the cost of transporting the bitumen divided by the volume of bitumen. Since this form of transportation does not require diluent, no allowance for diluent transportation costs is included.

<u>Example 4: Transportation Allowance Calculation</u>

- In the case of a clean crude bitumen (not blend) pipeline, there is no allowance for diluent supply to the Project, since it is not required to transport the bitumen.



Transportation Allowance = (\$10.00 x 10,000) / 10,000
= \$10.00/m^3 of Project Bitumen

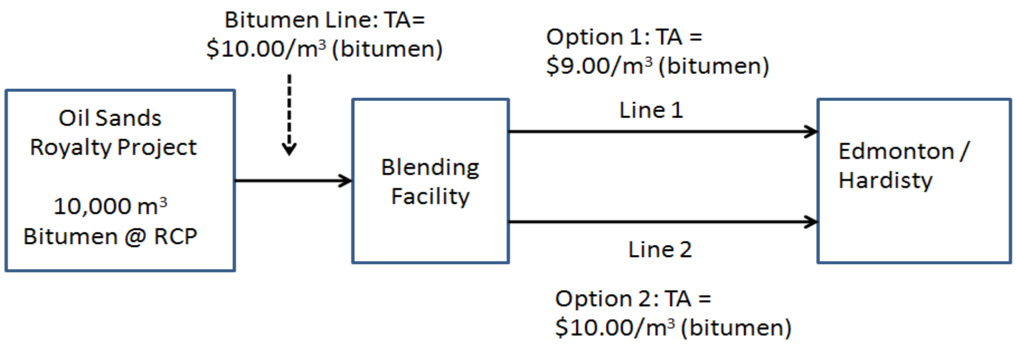
Example 5: A Project with Multiple Pipeline Segments[6] / Options (prior to January 01, 2017)

A Project's removal pipeline can consist of more than one segment. For example a Project could ship clean crude bitumen via a heated pipeline to a facility where it is blended with diluent and then shipped to Edmonton or Hardisty. In this case the transportation allowance for the removal pipeline is the sum of the allowances calculated for each segment, according to the rules which apply to each segment.

If a Project has more than one potential removal pipeline – i.e., it has pipeline connections to both Edmonton and Hardisty – it is the lowest cost option that is the removal pipeline for the Project for the purposes of calculating its transportation allowance. For simplicity, allowances for Line 1 and Line 2 below are already converted to dollars per cubic meter of bitumen including both diluent and blended bitumen transportation cost components as shown in Example 1 or Example 2.

<u>Example 5: Transportation Allowance Calculation</u>

-The transportation allowance for each pipeline is the ***sum*** of the segment costs;
- The transportation allowance is the ***lower*** of the two pipelines:



Transportation Allowance = lesser of ($10.00 + $9.00) and ($10.00 + $10.00) = $19.00/ m^3 for Project bitumen

4.2.5.3.5 Calculating the Transportation Allowance for a Project's Bitumen on and after January 1, 2017

To provide a more realistic transportation allowance calculation while retaining some features of the hypothetical BVM model, three critical changes in transportation allowances were implemented effective January 1, 2017: 1) a weighted average for multiple removal pipelines in a simple scenario and a optional prescribed transportation allowance (section 8, OSRR09) in complex scenarios, 2) clarification of rules on a take-or-pay arrangement and 3) clarification of rules on terminalling costs.

Simple Scenario: A weighted average for transportation allowance

[6] A pipeline segment means the continuous part of a removal pipeline (or a diluent pipeline) separated by the tank terminal(s) or blending plant(s). This term is defined only for the purpose of illustration in examples.

In a simple scenario of multiple removal pipelines connecting a Project to Hardisty/Edmonton, a weighted average of transportation costs is used to derive a transportation allowance. In complex scenarios of multiple pipelines, the Minister may prescribe a methodology/value of calculating a transportation allowance. Otherwise a least cost methodology described in Example 5 applies.

The simple scenario requires multiple removal pipelines connecting a Project with Hardisty/Edmonton without any terminalling between the Project and Hardisty/Edmonton, a single oil sands product containing Project bitumen and the determination of Project-specific transportation volumes for the single oil sands product on each removal pipeline.

> Note: The transportation allowance is calculated based on an average of the transportation rates for each removal line, weighted according to the respective volume of oil sands product actually transported on each removal line during the month in question.
>
> Examples are for a Project requiring to value 10,000 m^3 of bitumen using the BVM. 3,958 m^3 of diluent and 13,887 m3 of blended bitumen are hypothetically transported for the BVM. Actual transported volumes on pipelines would be different from those hypothetically transported volumes.

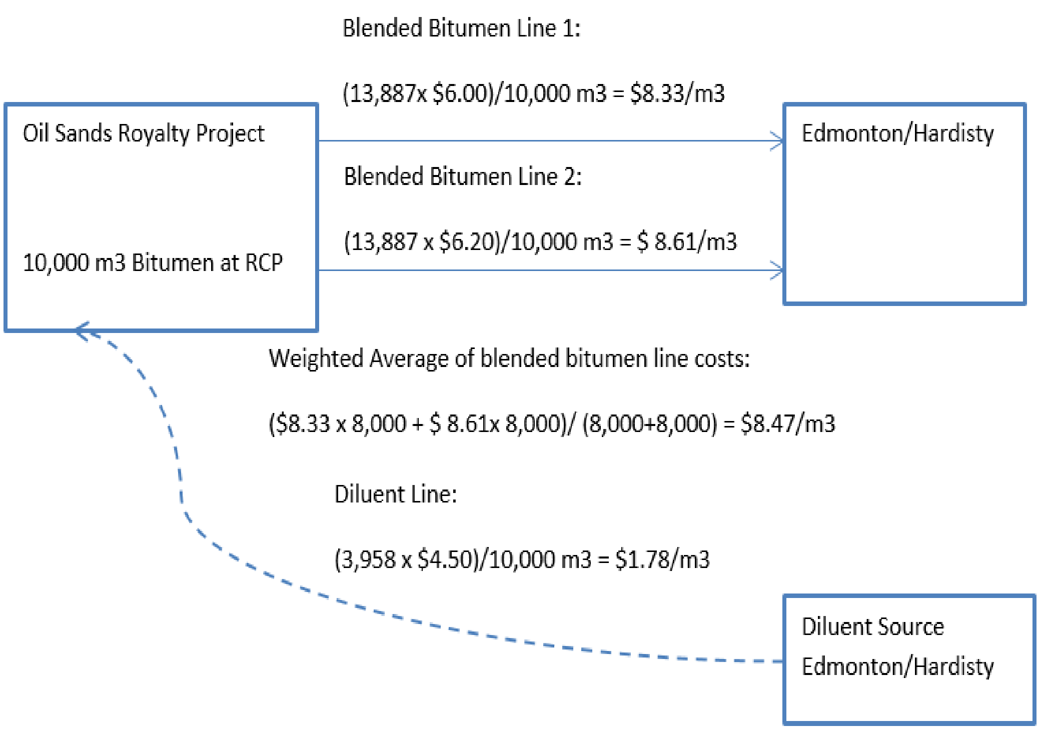
Example 1: A Project with Multiple Blended Bitumen Pipelines and a Diluent Line (Simple Scenario)

A Project ships blended bitumen via two pipelines from the Project to Edmonton/Hardisty. The volumes of the blended bitumen transported on each pipeline can be determined. A diluent line transports diluent from Edmonton/Hardisty to the Project. The average of transportation costs weighed by transported volumes plus the diluent transportation cost is the transportation allowance.

Assume a tariff on blended bitumen line 1 of \$6.00/m^3, a tariff on blended bitumen line 2 of \$6.20/m^3 and a diluent tariff of \$4.50/m^3. Assume the blended bitumen volume actually transported on line 1 is 8,000 m^3, the blended bitumen volume actually transported on line 2 is 8,000 m^3 and the actual volume crossed the royalty calculation point is 10,000 m^3 (Actual transported volumes are likely to be different from hypothetical ones). Also, assume that each of the pipelines is a single pipeline without any terminalling and tankage.

Example: Transportation Allowance Calculation

- The transportation cost for each blended bitumen pipeline in terms of bitumen is the hypothetic blended bitumen volume multiplied by the actual blended bitumen tariff divided by the RCP bitumen volume.
- The transportation cost for both blended bitumen pipelines is the average of each line's transportation cost weighted according to the actual transported volume on each line.
- The transportation allowance is the sum of transportation costs for both blended bitumen and diluent.



Transportation Allowance = $8.47 + $1.78 = $10.25 /m3 for Project bitumen

Example 2: A Project with Multiple SCO Pipelines where each pipeline is a single pipeline that carries only one oil sands product and No Diluent Line (Simple Scenario)

An upgrader is immediately adjacent to a Project. After upgrading, the Project ships SCO via two single pipelines from the Project to Edmonton/Hardisty. The volumes of SCO transported on each pipeline can be determined. No diluent line transports diluent from Edmonton/Hardisty to the Project because the upgrader provides diluent directly to the Project. The average of transportation costs weighed by transported volumes is the transportation allowance.

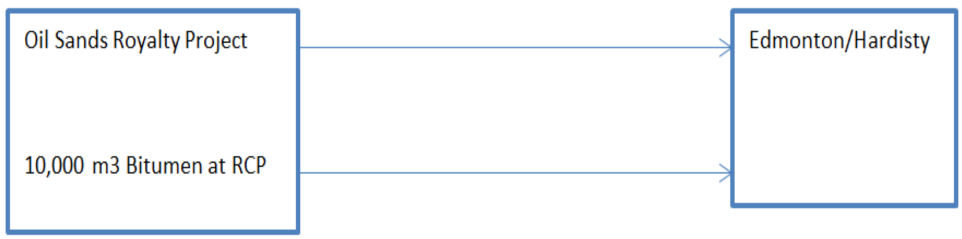
Assume a tariff on SCO line 1 of $5.00/m^3$, and a tariff on SCO line 2 of $5.20/m^3$. Assume the SCO volume actually transported on line 1 is 8,000 m^3, the blended bitumen volume actually transported on line 2 is 8,000 m^3 and the actual volume crossed the royalty calculation point is 10,000 m^3. (Actual transported volumes are likely to be different from hypothetical ones).

Example: Transportation Allowance Calculation

- In the absence of a diluent line, each removal pipeline transportation rate is used to calculate a proxy for diluent transportation.
- A conversion factor of 1.22 is used to convert a SCO tariff to a dilbit tariff and another conversion factor of 0.92 is used to convert a SCO tariff to a diluent tariff.
- The transportation allowance is the average of each line's transportation cost weighted according to the actual transported volume on each line.

SCO Line 1:

(13,887x $5.00 x 1.22 + 3,958 x $5.00 x 0.92) /10,000 m3 = $10.29/m3



SCO Line 2:

(13,887x $5.20 x 1.22 + 3,958 x $5.20 x 0.92) /10,000 m3 = $10.70/m3

Transportation Allowance = ($10.29 x 8,000 + $ 10.70x 8,000)/ (8,000+8,000) = $10.50/m3 for Project bitumen

Complex Scenario: A prescribed transportation allowance

Complex transportation scenarios may be reviewed closely by Alberta Energy. Upon application by a Project operator, the Minister of Energy may in his/her discretion decide to prescribe a Project-specific methodology or value for a transportation allowance. In general, as per section 5(1)(e) of the BVM regulation, the lowest cost aggregate pipeline rule applies in a complex scenario. However, any operators who may be in the following listed situations should contact the Manager, Royalty - Royalty and Tenure Operations, (See Appendix G, “Contact Information”) Department for further details:

- There are multiple removal pipelines with one or more terminals in total;
- The Project has multiple oil sands products; or
- The Project-specific transportation volumes can not be determined due to the comingling of oil sands products.

Take or Pay Contracts:

A take or pay arrangement is defined in the BVM Regulation as a contract under which the operator is obligated to pay a pipeline company a specific amount regardless of actual transported volumes.

The bitumen valuation methodology is a hypothetical model to calculate bitumen prices sold at non-arm's length. To retain some features of the hypothetical BVM model, in a case of a take-or-pay arrangement, only the contracted volume instead of the actual transportation volume should be used to calculate the tariff on a pipeline.

For the transportation allowance calculation, the tariff on a pipeline typically equals the monthly charge divided by the contracted volume, if such volume is specified in a take or pay contract.

For example, we assume a monthly charge of $10,000,000 for the contracted volume of 2,000,000 m^3 per month in a take or pay arrangement. For the transportation allowance calculation, the tariff = $10,000,000/2,000,000 m^3 = $5/$m^3$ regardless of actual transportation volumes.

Some take or pay arrangements contain a monthly charge for a base transportation volume and another monthly charge for an additional volume. For example, we assume a monthly charge of $10,000,000 for the first 2,000,000 m^3 per month and $2,000,000 for the additional 1,000,000 m^3 per month in a take or pay arrangement. Both volumes of 2,000,000 m^3 and 1,000,000 m^3 are contracted volumes in a take or pay arrangement. For the transportation allowance calculation, the tariff = ($10,000,000 + $2,000,000)/(2,000,000 +1,000,000)= $4/$m^3$

Some take or pay arrangements may not specify contracted volumes transported on a pipeline because the entire pipeline is used to ship oil sands products from a Project. In this case, according to section 5(1.4)(c) of the BVM Regulation, we use the design capacity of the pipeline to calculate the transportation allowance. For instance, we assume a monthly charge of $10,000,000 for a pipeline with the design capacity of 2,500,000 m^3 per month in a take or pay arrangement. No specific contracted volume is specified except the design capacity. For the transportation allowance calculation, the tariff = $10,000,000/2,500,000 m^3 = $4/$m^3$.

Clarification of Rules on Terminalling Costs

The BVM Regulation has been amended to clarify how terminalling costs should be calculated in transportation allowance calculation. Slightly different rules apply to removal pipelines transporting blended bitumen or upgraded products, and diluent lines.

<u>Removal Pipelines</u>

In principle, the tariff of a removal pipeline typically includes the first instance of receipt terminalling charges and transmission tolls. The following definition may help understand the transportation allowance calculation.

- The "receipt terminalling charges" include fees to allow the receipt of oil sands products or diluent onto a pipeline. They include the short-term storage of no more than 5 days but exclude long-term storage.
- The "first instance of receipt terminalling charges" means the receipt terminalling charges that first arise after the Project for an oil sands product recovered from the Project. Subsequent charges are not accepted into the tariff calculation.
- The "transmission tolls" mean fees that are attributable solely to the

transmission or movement of oil sands products or diluent along a pipeline.

- The “delivery terminalling charges” mean fees, charges, surcharges, tariffs or any other costs incurred to provide delivery terminally or delivery tankage.

- Delivery terminalling charges and storage charges more than 5 days are not receipt terminalling charges.

The slightly different rules of the terminalling charge calculation apply to third party transactions and non-arm’s length transactions. For terminalling charges in a third party transaction, these charges would be used to calculate the first instance of receipt terminalling charge. For terminalling charges in a non-arm’s length transaction, if the pipeline is commissioned before January 01, 2017, there is no adjustment to the cost of service calculation (*Oil Sands Allowed Costs (Ministerial) Regulation*) that is being used except if there is any capital addition related solely to transmission or the first instance of receipt terminalling. Again, for non-arms’ length terminalling charges, if the pipeline is commissioned on or after January 01, 2017, the pipeline is given terminalling allowance but the terminalling assets are excluded from the cost of service calculation.

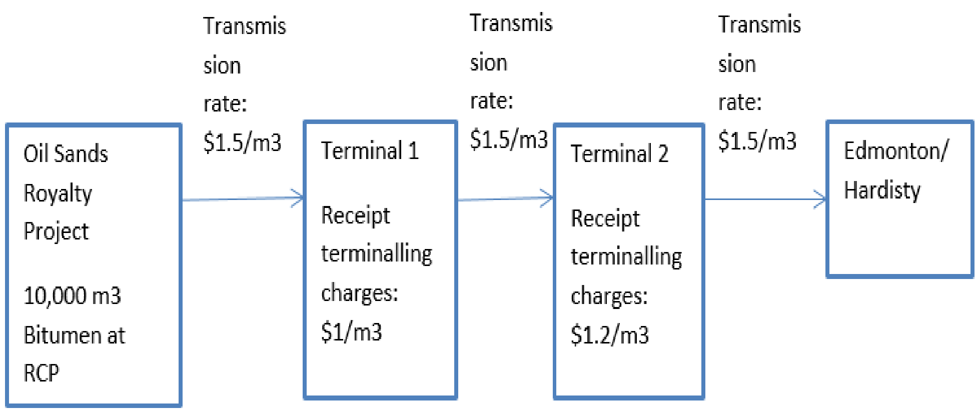
We continue our examples with a Project requiring to value 10,000 m^3 of bitumen using the BVM. 3,958 m^3 of diluent, and 13,887 m^3 of blended bitumen are hypothetically transported for the BVM.

Example 3: A Third Party Blended Bitumen Pipeline with multiple terminals and No Diluent Line

Only a blended bitumen pipeline owned by a third party connects a Project to Hardisty/Edmonton with two terminals along the pipeline. No diluent line exists for the Project. The first incidence of receipt terminalling charge is $1/$m^3$ and the second incidence of receipt terminalling charge is $1.2/$m^3$. The transmission rate is $1.5/$m^3$ for each of three segments separated by the two terminals.

Example: Terminalling Calculation

- The tariff of the blended bitumen line includes only the first instance of receipt terminalling charge and transmission rates.



Tariff=$1.5 + $1 + $1.5 + $1.5 /m3 = $5.5/m3

Transportation Allowance = (13,887x $5.50 + 3,958 x $5.50 x 0.754) /10,000 m3 =$9.28/m3

If a non-arm's length pipeline including pipeline terminals is commissioned prior to January 1, 2017 and no expansion of the pipeline is commissioned on or after January 1, 2017, the Minister shall determine the tariff for the transportation service using non-arm's length transaction rules under the Cost of Service calculation methodology described in the *OSACR*. In this case, existing methods used for transportation allowance calculation prior to January 1, 2017 are likely to still be used after January 1, 2017.

If a non-arm's length pipeline including pipeline terminals is commissioned prior to January 1, 2017 and the expansion of the pipeline is commissioned on or after January 1, 2017, the Minister shall determine the tariff for the transportation service by only including costs related to the first instance of receipt terminalling and transmission. Also, the pipeline should be used solely for the purpose of transmission of the oil sands products of the Project. The Minister shall determine the tariff using non-arm's length transaction rules under the Cost of Service calculation methodology described in the OSACR.

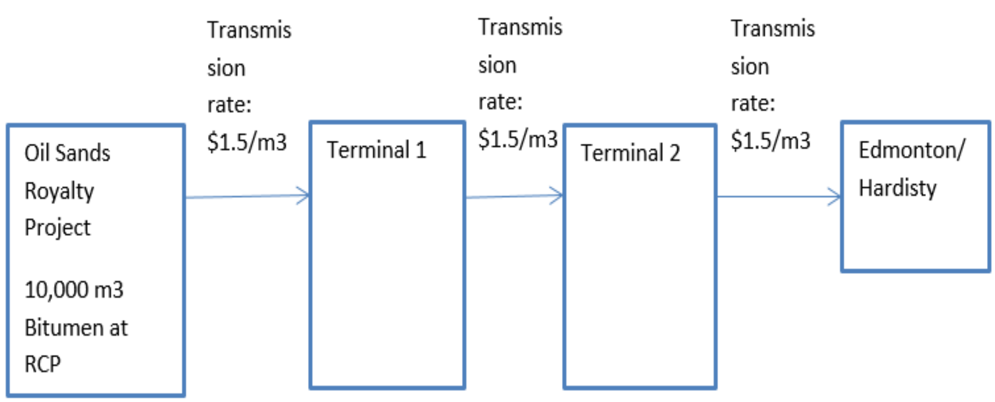
If a non-arm's length pipeline including pipeline terminals is commissioned on and after January 1, 2017, the minister shall determine the tariff for the transportation service including transmission using non-arm's length transaction rules under the OSACR and a terminalling allowance established by the Minister. In this case, the Cost of Service calculation will not include any costs related to terminalling as these costs will be reflected in the terminalling allowance. The Minister may, by order, establish from time to time with respect to any month a terminalling allowance.

Example 4: A Non-Arm's Length Blended Bitumen Pipeline with multiple terminals commissioned after January 1, 2017 and No Diluent Line

A blended bitumen pipeline owned by an affiliate commissioned after January 1, 2017, connects the Project to Hardisty/Edmonton with two terminals along the pipeline. Both terminals are used to provide receipt terminalling. No diluent line exists for the Project. In accordance with the OSAC Regulation, we assume the lesser of the amount charged and the Cost of Service giving rise to a transmission rate of $1.5/m^3 for each of three segments separated by the two terminals. The Minister determines a terminalling allowance of $1.4/m^3 where terminal 1 has a cost of $1.1/m^3 and terminal 2 has a cost of $1.2/m^3 according to the Cost of Service calculation under OSAC Regulation. The actual terminalling charges for two terminals do not enter the calculation of the transportation allowance.

Example: Terminalling Calculation

- The tariff of the blended bitumen line includes only transmission rates and the terminalling allowance established by the Minister.



Terminalling allowance = $1.4/m3

Tariff=$1.5 + $1.4 + $1.5 + $1.5 /m3 = $5.9/m3

Transportation Allowance = (13,887x $5.90 + 3,958 x $5.90 x 0.754) /10,000 m3 =$9.95/m3

Diluent Pipelines

If no diluent pipeline connects a Project to Hardisty or Edmonton, the charges of blended bitumen removal pipelines give rise to an estimate of diluent pipeline costs as shown in the above section.

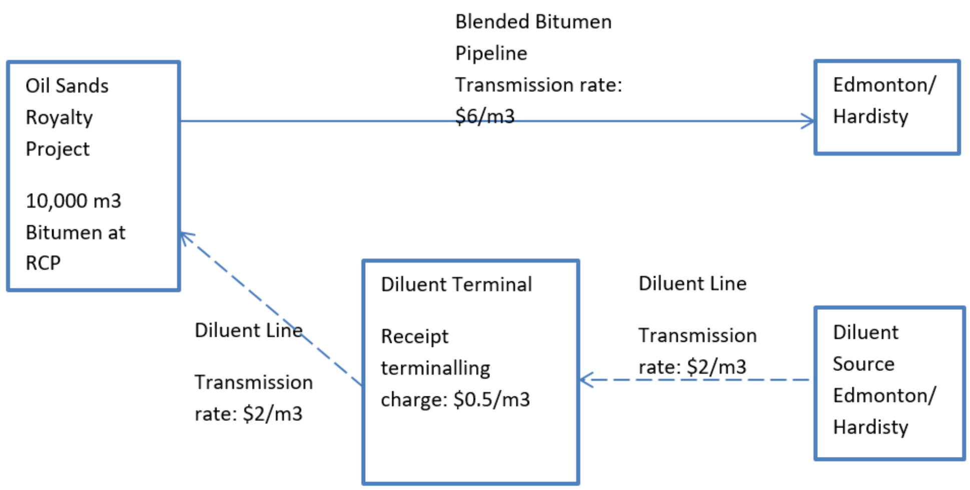
If a diluent pipeline connects a Project to Hardisty or Edmonton, the transportation rate of the diluent pipeline typically includes only transmission rates according to section 5(1.3) of the BVM Regulation. It is thought that the terminalling charge is not required for the hypothetical transportation of diluent to a Project under the BVM.

Example 5: A Third Party Blended Bitumen Pipeline and a Third Party Diluent Line with a terminal

A blended bitumen pipeline owned by a third party connects a Project to Hardisty/Edmonton. A diluent line owned by a third party connects Hardisty/Edmonton to a Project with a third-party terminal. The tariff on the blended bitumen removal pipeline is \$6/m3. For the diluent line, the receipt terminalling charge is \$0.5/m3 and the transmission toll is \$2/m3 for each of two segments separated by the terminal.

Example: Terminalling Calculation

- The tariff of the diluent line includes only transmission rates.



Diluent Tariff=\$2 + \$2/m3 = \$4/m3

Transportation Allowance = (13,887x \$6 + 3,958 x \$4) /10,000 m3 =\$9.92/m3

If a non-arm's length diluent pipeline including pipeline terminals is commissioned prior to January 1, 2017 and no expansion of the diluent pipeline is commissioned on and after January 1, 2017, the Minister shall determine the diluent tariff for the transportation service using non-arm's length transaction rules under the OSACR. In this case, existing methods used for diluent tariff calculation prior to January 1, 2017 are likely to still be used after January 1, 2017.

If a non-arm's length diluent pipeline including pipeline terminals is commissioned prior to January 1, 2017 and the expansion of the diluent pipeline is commissioned on and after January 1, 2017, the minister shall determine the diluent tariff for the transportation service only including transmission, using non-arm's length transaction rules under the OSACR.

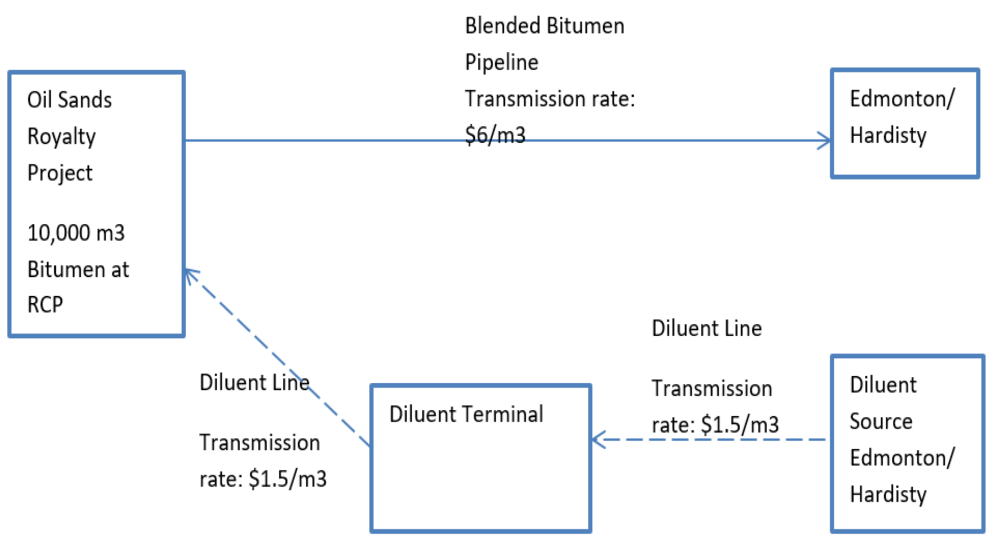
If a non-arm's length diluent pipeline including pipeline terminals is commissioned on and after January 1, 2017, the Minister shall determine the tariff for the transportation service only including transmission using non-arm's length transaction rules under the OSACR.

Example 6: A Third Party Blended Bitumen Pipeline and a Non-Arm's Length Diluent Pipeline with a terminal commissioned on or after January 1, 2017

A blended bitumen pipeline owned by a third party connects a Project to Hardisty/Edmonton. A diluent line, owned by an affiliate commissioned on and after January 1, 2017, connects Hardisty/Edmonton to the Project with a non-arm's length terminal. The blended bitumen line tariff is $6/m3. In accordance with the OSACR, we assume the lesser of the amount charged and the cost of service gives rise to the diluent transmission toll of $1.5/m^3$ for each of two segments separated by the terminal. No diluent terminalling charge should contribute to the calculation of the transportation allowance.

Example: Terminalling Calculation

- The tariff of the diluent line includes only transmission rates.



Diluent Tariff=$1.5 + $1.5/m3 = $3/m3

Transportation Allowance = (13,887x $6 + 3,958 x $3) /10,000 m3 =$9.52/m3

Any operators who have any questions about the terminalling cost calculation, they should contact the Manager, Royalty - Royalty and Tenure Operations, (See Appendix G, "Contact Information") Department for guidance.

Summary

For a Project requiring BVM the fair market value for its bitumen is the Hardisty Bitumen price for the Project minus the transportation allowance for the Project, calculated as described above. This fair market value is the "P" in the unit price formula described in section 4.2.5.2.

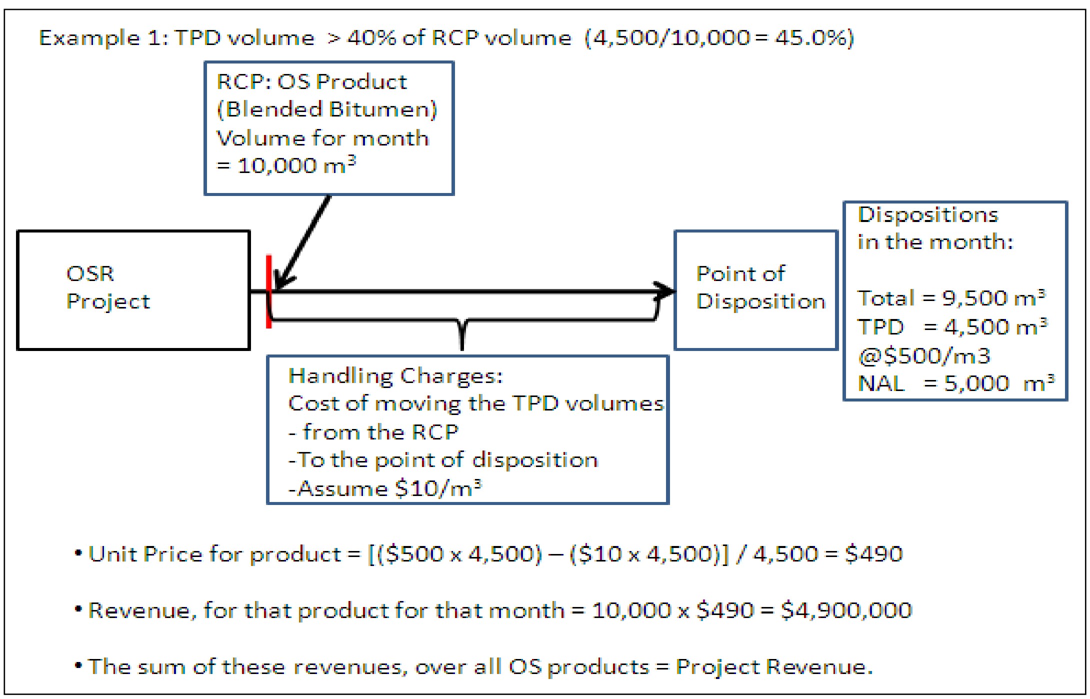
4.2.5.4 Examples of Oil Sands Unit Price and Project Revenue Calculations

Key points:

- The price obtained for dispositions in a month is used to value production royalty calculation point volumes in that month.
- Because of factors such as "off-project" storage, line-fill provision, or transit time to point of disposition, disposition volumes in a month need not equal production royalty calculation point volumes in that month.
- It is the ratio of third party disposition volumes to production royalty calculation point volumes that is compared to the third party disposition threshold when valuing royalty volumes.

Example 1: Third Party Dispositions are greater than or equal to 40% of Production royalty calculation point Volumes:

In this case the third party disposition can be used to value all production royalty calculation point volumes for royalty calculation purposes.



The Project revenue for the month is the sum of all revenues of the different oil sands products produced by the Project in that month.

In calculating the handling costs for the third party disposition volumes, where the handling costs are arm's length charges:

- If the charges are incurred on a per unit basis simply multiply the charge by the third party disposition volumes
- If a single charge is levied to transport all the disposed volumes (9500 m3 in

this example) the third party disposition handling costs can be calculated as:

- Total HC x (third party disposition / Total dispositions)

If the handling costs are incurred as NAL costs (i.e. on an affiliated non-project pipeline) the per unit cost determined by rules in section 6 of this guideline should be applied to each third party disposition unit.

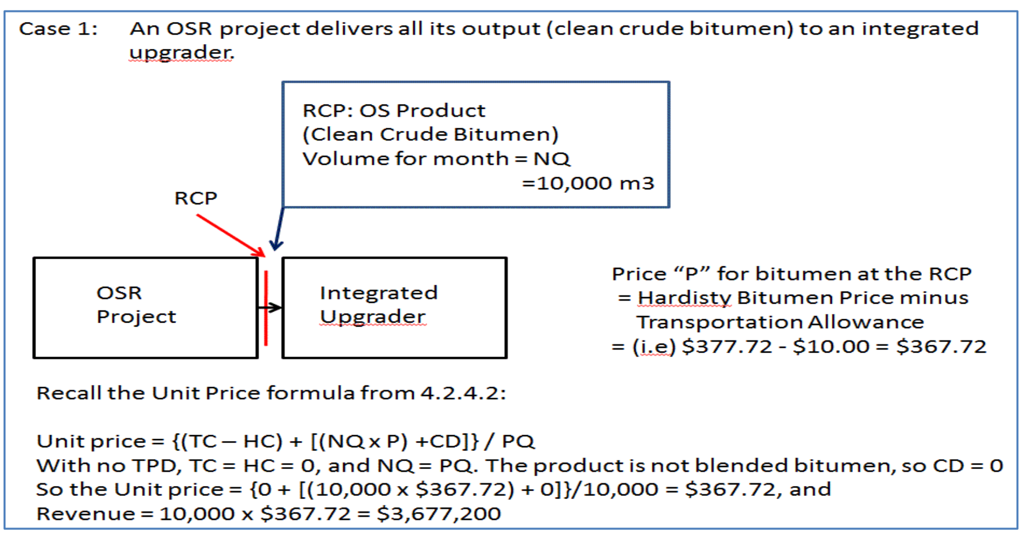
Example 2: No Third Party Dispositions (Non-Arm's Length Transactions)

In case 1, where an OSR Project delivers all its output to an integrated upgrader, a fair market value must be prescribed as the unit price of the oil sands product at the royalty calculation point. Where the oil sands product is cleaned crude bitumen or blended bitumen the BVMR is used in determining this fair market value for royalty purposes.

Note that the BVMR values a Project's bitumen, not its blended bitumen. If a Project's oil sands product is blended bitumen the Minister values the volume of clean crude bitumen contained in the blend at the royalty calculation point according to the BVMR. The value of the diluent actually included in the Project's blended bitumen at the royalty calculation point is then "added in" in calculating the unit price for the Project's blended bitumen. (This is "CD" in section 4.2.5.2).

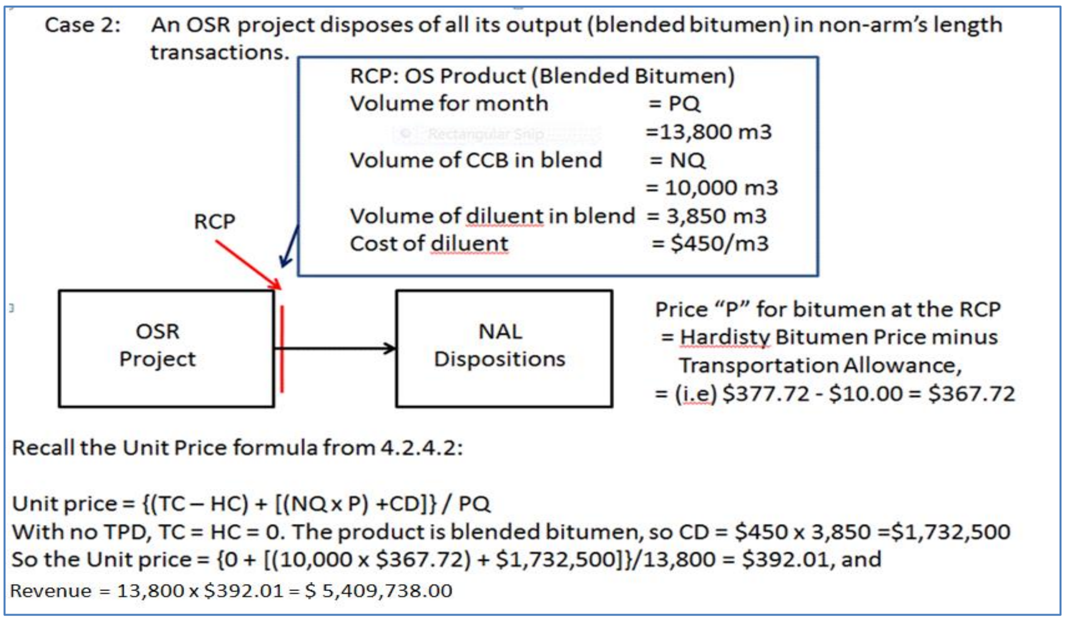
Also, because the BVMR includes a transportation allowance component, "actual" handling charges related to the Project's clean crude bitumen or blended bitumen are not included in the unit price calculation.

Here we illustrate two cases. In the first, an oil sands Project disposes of all its bitumen output to an integrated upgrader. In the second, an oil sands Project produces blended bitumen, which is all disposed of in NAL transactions.



In case 2, an OSR Project disposes of all its output in non-arm's length transactions, in the calculation of the cost of diluent in the blend at the royalty calculation point, it is the actual volume and price of diluent (at the royalty calculation point) which are used, not the diluent volume and price used in the BVM calculation to derive the price of bitumen (included in the blend) at the royalty calculation point. The actual diluent may not be the CRW condensate assumed in the BVM calculation: it might, for example, be SCO or naphtha from an upgrader.

Due to the addition of “CD” (cost of diluent), the product (blended bitumen) has a higher unit price than the product (cleaned crude bitumen) in case 1. However, this **does not** imply a greater royalty obligation in case 2: remember that the “CD” is deducted from Project revenue to obtain “gross revenue” for the calculation of gross revenue royalty, and an allowed cost is deducted from Project revenue to obtain “net revenue” for the calculation of net revenue royalty.



Example 3: Third Party Dispositions < 40% of Production royalty calculation point Volumes

In this case, the volume of third party dispositions is too small to allow those dispositions to value all the volumes of the oil sands products at the royalty calculation point. A volume at the royalty calculation point equal to the volume of third party dispositions will be valued according to those dispositions: the remaining volumes at the royalty calculation point will need to be valued at “fair market value” – in this example, according to the BVMR.

Consider an OSR Project producing blended bitumen as described in case 2, above. For simplicity, let total dispositions in the Period equal the royalty calculation point volume of 13,800 m3 (= PQ). Assume 3,800 m3 were disposed of in third party dispositions at a price of $385/m3, and the cost of transporting those third party disposition volumes to the point of disposition was $6/m3.

As 3,800m3/13,800m3 = 27.5%, < 40%, these dispositions cannot value all the volumes at the royalty calculation point: they will value 3,800 m3 at that point.

Assume that the BVM value of bitumen at the Project (Hardisty Bitumen Price – transportation allowance) = $367.72/m3. If there were 10,000 m3 of clean crude bitumen in the 13,800 m3 of blend at the royalty calculation point, we can calculate

- NQ = the amount of bitumen in the NAL dispositions (10,000 m3 of blend) to be (10,000/13,800) x 10,000 = 7,246.4 m3.

By similar reasoning, we can calculate CD, the cost of diluent in the NAL volume as (10,000/13,800) x 3,850 x $450 = $1,255,434.78– using the diluent volume and value from case 2 again.

<u>Recalling the unit price formula again:</u>

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

<u>Substituting the values from above:</u>

$$\text{Unit price} = \frac{\{((3{,}800 \times \$385) - (3{,}800 \times \$6)) + [(7246.4 \times \$367.72) + \$1{,}255{,}434.78)]\}}{13{,}800}$$

Unit price = $388.43/m3, of blended bitumen.

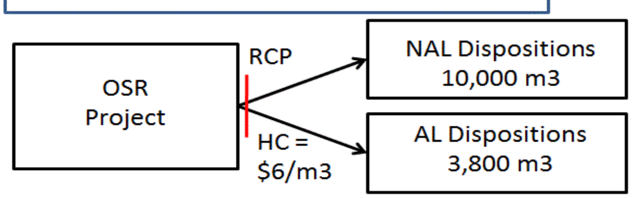
Project Revenue = $388.43 x 13,800 = $5,360,334.

Example 3: An OSR project's output (blended bitumen) is disposed of in both third party and non-arm's length transactions.

RCP: OS Product (Blended Bitumen)
Volume for month = PQ =13,800 m3
Volume of CCB in blend = NQ = 10,000 m3
Volume of diluent in blend = 3,850 m3
Cost of diluent = $450/m3

Price "P" for bitumen at the RCP = Hardisty Bitumen Price minus Transportation Allowance, = (i.e) $377.72 - $10.00 = $367.72

Price of blended bitumen in AL transactions = $385/m3



Unit price = {(TC – HC) + [(NQ x P) +CD]} / PQ
Here, (TC-HC) = ($385x3,800) –($6x3,800) = $1,440,200; NQ=(10,000/13,800)x10,000 = 7246.4
CD = $450 x 3,850 x (10,000/13,000) = $1,732,500
So the Unit price = {$1,440,200 + [(7246.4 x $367.72) + $1,255,455]} / 13,800 = $388.43 / m3
Revenue = 13,800 x $388.43 = $5,360,334

4.2.5.5 Negative Unit Price

A unit price for an oil sands product is normally positive, but can be negative where handling charges exceed the total consideration received for the product.

It is important to understand that the Crown does not provide negative royalty compensation. If the unit price of an oil sands product is negative, the royalty payable on that product defaults to zero.

A similar situation can arise in a Project selling blended bitumen, where, even though the unit price for the blended bitumen is positive, the cost of diluent in the blended bitumen exceeds the value of the blended bitumen calculated from the unit price. Here too, the royalty payable defaults to zero.

Examples of how negative unit prices and/or a negative value for bitumen contained in blended bitumen affect royalty calculation are provided in OSRR09 guideline section 4.3 and 4.4, for pre and post-payout Projects respectively.

4.3 The Royalty Calculation for Pre-Payout Projects

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 29(1)

Oil sands royalty is paid in cash, but is based on the Crown's ownership of a physical share of the oil sands products produced by a Project: the transfer of these Crown volumes to the lessee results in a cash "royalty compensation" payment to the Crown.

The Crown's royalty share of an oil sands product from a pre-payout Project is calculated monthly at the gross revenue royalty rate (RG%) the volumes of each oil sands product delivered at its RCP in that month.

These Crown royalty volumes are transferred to the lessee immediately downstream of the royalty calculation point. This transfer triggers a cash payment to the Crown equal to the value of the Crown's royalty share, established using its calculated unit price.

For a pre-payout Project, this royalty compensation must be paid to the Crown no later than the last day of the month following the month in which the product was delivered at the royalty calculation point: i.e., for product delivered to the royalty calculation point in May, royalty compensation must be paid by the last day of June.

RG% is the pre-payout gross revenue royalty rate calculated in accordance with the following formula:

$R_G\% = 1\% + \{FG\ (A – B)\}$

Where,

$R_G\%$ = The Crown's royalty share of the quantity expressed as a percentage;

F_G = 8% divided by $65 per barrel;

A = Lesser of the WTI price for the given month calculated in accordance with subsection (3) and $120 per barrel;

B = Lesser of A for the month and $55 per barrel.

RG% varies from 1%, when the $Cdn price of WTI is less than or equal to $55/bbl for the month, to 9%, when the WTI price is $120/bbl or more. Specifically:

$R_G\%$ = 1%, when $Cdn WTI < $55,

$R_G\% = 1\% + \{(8\%/\$65) \times (WTI – \$55)\}$ when $\$55 < WTI < \$120$

$R_G\% = 9\%$, when $Cdn WTI ≥ $120

The Department publishes the pre-payout gross royalty rate RG% for each month in an Information Letter published on the Department's website. From the Department's website (http://www.energy.alberta.ca/), navigate to "Related Links" and "Information Letter".

Where the oil sands product is clean crude bitumen contained in blended bitumen, the royalty compensation payable to the Crown is calculated by multiplying the volume of blended bitumen containing the Crown share of clean crude bitumen by the greater of the unit price for blended bitumen or zero, then subtracting from this amount the lesser of that amount and the cost of diluent included in that volume of blended bitumen. This ensures that the royalty payable is not a negative amount.

Example 1:

Let $Cdn WTI = $55, so RG% = 1%; if a Project delivered 100 units of clean crude bitumen to its royalty calculation point in a month, with a unit price of $50, then the Crown's royalty share would be 1% x 100 = 1 unit of clean crude bitumen, and the royalty compensation due would be 1 unit x $50 = $50.

Example 1a:

Let RG% = 1%. If a Project delivered 150 units of blended bitumen, containing 100 units of clean crude bitumen and (ignoring shrinkage) 50 units of diluent to its royalty calculation point in a month, with a unit price for blended bitumen of $50 and a diluent cost of $70/unit, then:

- the Crown's royalty share of clean crude bitumen is 1% x 100 = 1.0 unit,
- the amount of blended bitumen containing that share is 1.5 units, and the amount of diluent in the amount of blended bitumen is 0.5 units, therefore
- royalty compensation payable = (1.5 units x $50) – (0.5 x $70) = $40.

Example 2:

As in example 1a, but with unit price of blended bitumen = $20 and cost of diluent $80/unit:

The Crown's royalty share of clean crude bitumen is 1% x 100 = 1.0 unit,

- the amount of blended bitumen containing that share is 1.5 units,
- the value of that blended bitumen is 1.5 x $20 = $30.00,
- the cost of diluent in that amount of blended bitumen is 0.5 x $80 = $40, so
- royalty compensation payable is $30 - $30 = 0, not $30 - $40 = -$10. ($30 < $40)
- in this case, the excess of the diluent cost over the value of the blend ($10) is, by s.15(8) of the OSACR, an allowed cost of the Project for the next month.

Example 3:

As in example 2, but with the unit price for blended bitumen = -$10 per unit:

- royalty compensation = $0 - $0 = $0. (The Crown share multiplied by $0 > -$10, minus the lesser of that amount ($0) and $40.)

- here the entire cost of diluent ($40) is a deemed allowed cost for the next month.

The total royalty compensation payable in each month by a pre-payout Project is the sum of the royalty compensations payable in respect of each oil sands product produced by the Project in that month.

A Simplification:

Where, in a month, for a pre-payout Project:

- the unit price for each oil sands product is greater than or equal to zero, and
- the value of the blended bitumen (if any) containing the Crown's share of clean crude bitumen is greater than or equal to the cost of the diluent in that volume of blended bitumen.

The royalty compensation payable by the Project can be simply calculated as:

RG% x Gross Revenue

Where Gross Revenue = Project Revenue – Cost of Diluent

4.4 The Royalty Calculation for Post-Payout Projects

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 29(2)

The Crown's royalty share of an oil sands product from a post-payout Project in a Period is based on the greater of the gross royalty for the Period and the net royalty for the Period.

As with pre-payout Projects, the gross royalty rate (RG%)can vary from 1% to 9%. This is based on the average price of WTI in $Cdn for the Period. The average WTI price for a Period is the simple average of the WTI prices for each month in the Period.

The net royalty rate (RN%) for a Project for a Period is the product of the net royalty percentage factor (NRPF) multiplied by the ratio of the Project's net revenue (NR) to its gross revenue (GR) for the Period. NRPF is calculated as:

{25% + (FN (A – B)};

Where,

FN = 15% divided by $65 per barrel

A = lesser of the WTI price for the year containing the Period and $120 per barrel

B = lesser of A for that year and $55 per barrel

The net royalty percentage factor varies from 25%, when the $Cdn WTI price for the Period is less than or equal to $55, to 40%, when the WTI price is greater than or equal to $120. Specifically:

RN% = 25% x (NR/GR), when \$Cdn WTI ≤ \$55

RN% = {25% + [(15%/\$65) x (WTI –\$55)]} x (NR/GR), when \$55 < WTI <\$120

RN% = 40% x (NR/GR), when \$Cdn WTI ≥ \$120

Example 1:

Assume a post-payout Project delivers 10,000 units of an oil sands product to its royalty calculation point in a Period. Let the average WTI price for the Period be \$75, so RG% for the Period is 3.46154%, and the net royalty percentage factor is 29.61538%.

Let the unit price of the product be \$100, so GR = \$1,000,000. Let allowed costs for the Period be \$800,000, so NR = \$200,000. Then RN% = 29.61538% x (\$200,000/\$1,000,000) = 5.92308%.

As RN%= 5.92308% is greater than RG% = 3.36154%, the net royalty rate establishes the Crown's royalty share for that Period, which is equal to 592.31 units of product.

When this Crown share is transferred to the owner of the lessee's share immediately after the royalty calculation point, royalty compensation is triggered. For bitumen: 592.31 units x \$100 per unit = \$59,231

As in the case of pre-payout Projects, the royalty compensation payable to the Crown in respect of each oil sands product (other than blended bitumen) for the disposition of the Crown royalty share is calculated by multiplying the Crown share of each oil sands product by the greater of the unit price for that product and zero. If the unit price is a negative value, the royalty payable on that product is zero, not a negative amount.

Where the oil sands product is clean crude bitumen contained in blended bitumen, the royalty compensation payable to the Crown is calculated by multiplying the volume of blended bitumen containing the Crown share of clean crude bitumen by the greater of the unit price for blended bitumen or zero, then subtracting from this amount the lesser of that amount and the cost of diluent included in that volume of blended bitumen. This ensures that the royalty payable is not a negative amount.

Although negative unit prices (and negative values for bitumen contained in blended bitumen) do not result in negative royalties, they do affect the net revenue royalty rate because they are incorporated in the calculation of gross and net revenue, and so affect the ratio (NR/GR).

The Department publishes the gross royalty rate (RG%) and the net royalty percentage factor (NRPF) for a Period at the end of each Period, in its Information Letter for December. Example of the Information Letter for December is shown below:

Alberta

Oil Sands Monthly Royalty Rates Information

Production Month: December 2016

Royalty Information

Pre-Payout Gross Royalty Rate:	1.73846%	(based on Production Month actual WTI Price)
Post-Payout Gross Royalty Rate:	1.09108%	(based on the average WTI Price for Production Year)
Post-Payout Net Royalty % Factor (NRPF):	25.17077%	(based on the average WTI Price for Production Year)

WTI Prices and Exchange Rates

Month	Act/Est	WTI Price ($US)	Exchange Rate ($US/$CDN)	WTI Price ($CDN)
Jan 2016	Act	$37.33	0.70307914	
Feb 2016	Act	$31.78	0.72484253	
Mar 2016	Act	$30.62	0.75607610	
Apr 2016	Act	$37.96	0.78011813	
May 2016	Act	$41.12	0.77267242	
Jun 2016	Act	$46.80	0.77545884	
Jul 2016	Act	$48.85	0.76626591	
Aug 2016	Act	$44.80	0.76956443	
Sep 2016	Act	$44.80	0.76285409	
Oct 2016	Act	$45.23	0.75463440	
Nov 2016	Act	$49.94	0.74415836	
Dec 2016	Act	$45.76	0.75022413	= $61.00
Average		$42.08	0.75499571	= $55.74

Royalty payable for a Period must be paid to the Crown no later than the end of the fourth month after the end of a Period – i.e. by April 30th for a Period ending December 31st.

A Simplification:

Where, in a Period, for a post-payout Project:

- the unit price for each oil sands product is greater than or equal to zero, and
- the value of the blended bitumen (if any) containing the Crown's share of clean crude bitumen is greater than or equal to the cost of the diluent in that volume of blended bitumen, then:

The royalty compensation payable by the Project is simply the greater of:

RG% x Gross Revenue, and

NRPF x Net Revenue

Where Gross Revenue = Project Revenue – Cost of Diluent, and

Net Revenue = Project Revenue – (Allowed Costs – Other Net Proceeds)

4.4.1 Installments

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 33(6)

Post-payout Projects must pay, each month, an installment towards the royalty they will pay for the Period.

Each month, the Department publishes in its Information Letter an estimated annual gross royalty rate (RGest%) and estimated annual net royalty percentage factor, which are to be used in calculating these installments.

The installment due in each month is the greater of:

- RGest% x Gross Revenue for that month and all preceding months in the Period, and
- Estimated annual net royalty % factor x (ENR/EGR) x Gross Revenue for that month and all preceding months in the Period, where ENR and EGR are respectively estimated net revenue and estimated gross revenue for the entire Period.

<u>Minus</u>

The aggregate of installments paid in preceding months of the Period.

Alternatively, since “estimated annual royalty percent x (ENR/EGR)” is the estimated net revenue royalty rate for the Period (RNest%), the installment due in respect of a particular month is the greater of RGest% and RNest% for that month, multiplied by the Project’s year to date (YTD) Gross Revenue, minus previous installments.

Example:

Assume at the end of August a post-payout Project has received GR(YTD) = $1,000,000 and incurred allowed costs (YTD) of $800,000, so NR (YTD) = $200,000.

The Department publishes, for August, estimated annual gross royalty rate RGest% = 3.36154% and estimated annual net royalty percentage factor of 29.61538%.

If the Project expects, for the Period, EGR = $1,600,000 and ENR of $320,000, then (RNest%) = ($320,000/$1,600,000) x 29.61538% = 5.29308%. This larger value (than 3.36154%) is used to calculate the installment value: 5.29308% x $1,000,000 = $52,930.80.

If previous installments in the Period had totaled $45,000, the August installment would just be the difference:

$52,930.80 - $45,000 = $7,930.80.

Installments are due no later than the last day of the following month.

If the installment calculated in respect of any month of the Period is negative, that amount is deducted from the installment due in the next (and succeeding) month(s) until it is eliminated.

If the negative installment calculated for a month in a Period is, in the Minister’s opinion, greater than the total of the amounts that will be payable for the rest of the Period, the Minister will refund the difference between these amounts (i.e. total installments paid – estimated due for the entire Period) no later than the last day of the month following the month in which this was reported.

At the end of the Period, the difference between the total of installments paid and the royalty payable for the Period must be paid (or refunded) before the last day of the fourth month after the end of the Period – i.e. April 30th for a period ending December 31st.

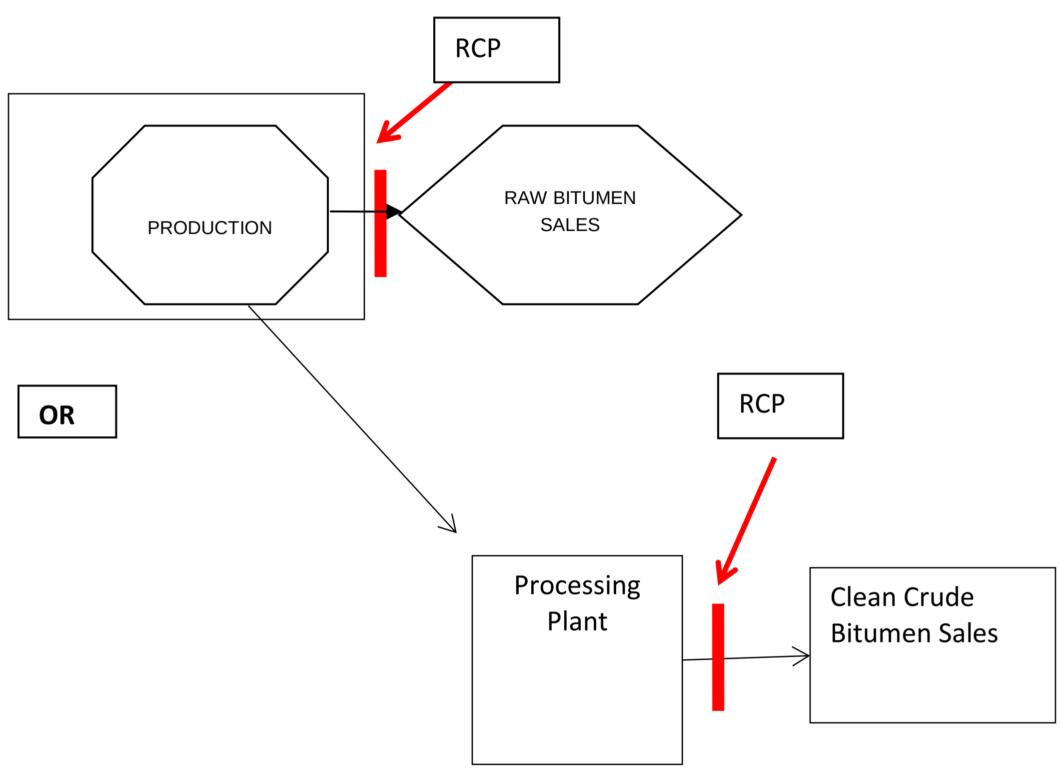
4.5 Examples of Project Configurations

Project Sales and Revenues

Project sales are sales of all oil sands products obtained from oil sands rights approved as part of the Project description.
The revenue calculated as the royalty volume of a product multiplied by the unit price (sales less handling charges) for that product is called the product revenue.
The sum of product revenues is the Project revenue.
Gross revenue (GR) is the Project revenue less the cost of diluent included in blended bitumen, if blended bitumen is a product of the Project.
Net revenue (NR) is the Project revenue less allowed costs. The allowed costs are reduced by the amount of any other net proceeds.

4.5.1 An OSR Project that Produces Raw Bitumen

Figure 1: An OSR Project with no processing facilities



Project Output

- This type of Project produces raw bitumen.

Royalty Calculation Point

- The point of disposition is the key to determine the royalty calculation point in this case.
- If raw bitumen is disposed of before being processed to cleaned crude bitumen, the royalty calculation point is where the bitumen is removed from Project lands (the first part of the figure above).
- If, before being disposed of, the raw bitumen is processed in a plant which is not part of the Project, the royalty calculation point for the Project is deemed to be the outlet of the processing plant(the second part of the figure above).

Allowed Costs and Handling Charges

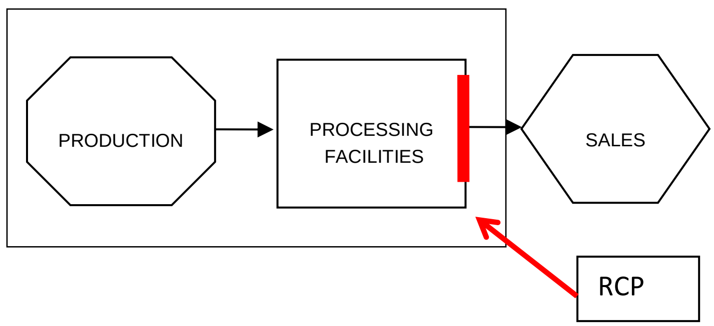
- Cleaned crude bitumen is the first marketable oil sands product for royalty calculation purposes. However, under the provisions of OSRR'09 section 32(9), (the first part of the figure above) the royalty calculation is based on the Minister's determination of the revenue that could have been obtained had the bitumen been cleaned. In making this determination, the Minister estimates the fair market value of cleaned crude bitumen. This amount, not the amount received for the sale of raw bitumen, is used to calculate the unit price. The allowed costs of the Project are those costs incurred to deliver the raw bitumen to the royalty calculation point. The Project's handling charges will include the estimated cost of transporting the raw bitumen from the place at which it was disposed of to a place at which could be cleaned and the estimated cost to process the raw crude bitumen to produce clean crude bitumen.
- If, before being disposed of, the raw bitumen is processed in a plant which is not part of the Project (the second part of the figure above) the costs of transporting the raw bitumen to the plant and processing the raw bitumen are allowed costs of the Project. Non-project processing plants provide a basic service to the Project.

Allowed Costs versus Handling Charge Deductions:

> For all Project configurations, handling charges are those charges incurred between the royalty calculation point and the point of disposition (see OSRR'09 section 32(1)(a). Allowed Project costs are those costs incurred before the oil sands product is delivered to the royalty calculation point. A charge cannot be both a handling charge and an allowed cost.

4.5.2 An OSR Project that includes Processing Facilities

Figure 2: An OSR Project that includes processing facilities



Project Output

- This type of Project produces cleaned crude bitumen or other oil sands products.

Royalty Calculation Point

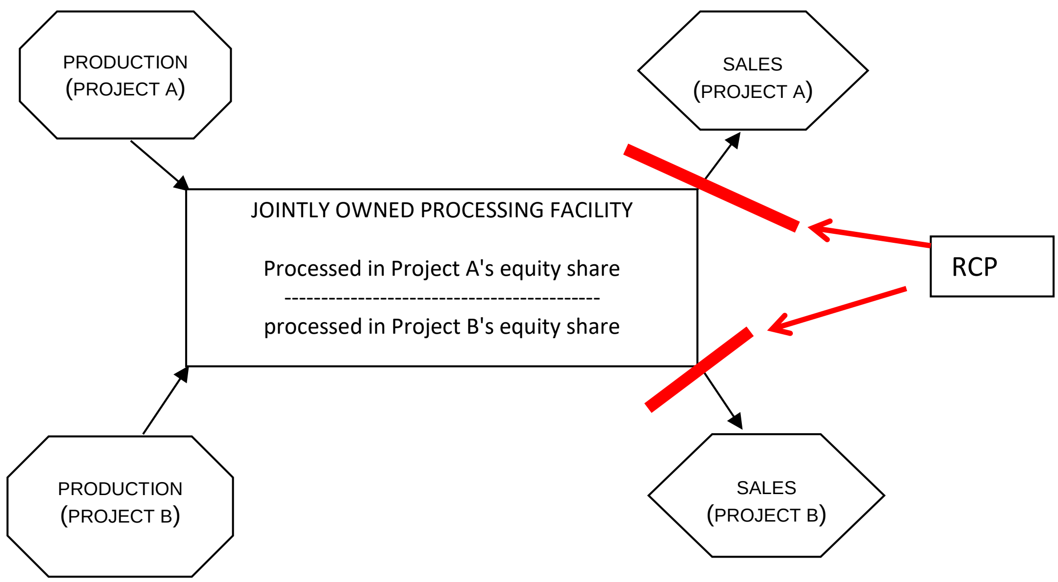
- The royalty calculation point is at the outlet of the processing plant, and royalty is calculated on the volume of cleaned crude bitumen at that point.

Allowed Costs

- Costs attributed to the production and cleaning or processing of crude bitumen are deducted as allowed costs.

4.5.3 OSR Projects with Jointly Owned Processing Facilities

Figure 3: Two projects with joint ownership of processing facilities



Project Output

- This type of Project produces cleaned crude bitumen or other oil sands products.

Royalty Calculation Point

- This is at the outlet of the processing plant.

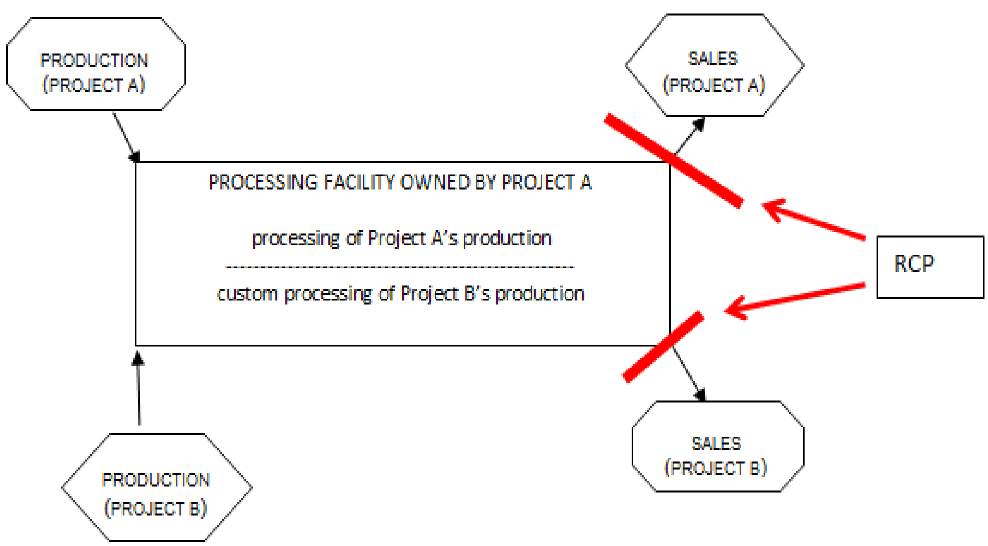
Allowed Costs

- Each project can deduct allowed costs attributed to its production of raw bitumen and to the proportion of processing costs that corresponds to its ownership share in the facility. The processing done for each Project is assumed to be in proportion to the Project's ownership share of the processing facility. For example, if each project owner owns a 50% share, the processing for each Project is assumed to be 50%.

If the quantities processed are not in the same proportion as the ownership, a cost equalization payment is made to account for the difference. The cost equalization payment ensures that one owner is not covering costs for the other when royalty is calculated. The cost equalization payment is treated as a custom processing charge as described in section 4.5.4 "An OSR Project that Provides Custom Processing Services" below. If a processing facility that is wholly or partly owned by a Project participant (or affiliate) is not included in the Project, the custom processing service provided by the facility to the Project is considered a basic service. The cost rules for NAL transactions apply. (See Chapter 6, Non-Arm's Length Transactions and Affiliates)

4.5.4 An OSR Project that Provides Custom Processing Services

Figure 4: An OSR Project with processing facilities that processes the output (production) from and owned by another Project



Project Output

- This type of Project produces cleaned crude bitumen or other oil sands products.

Royalty Calculation Point

- This is at the outlet of the processing plant, for both Projects.

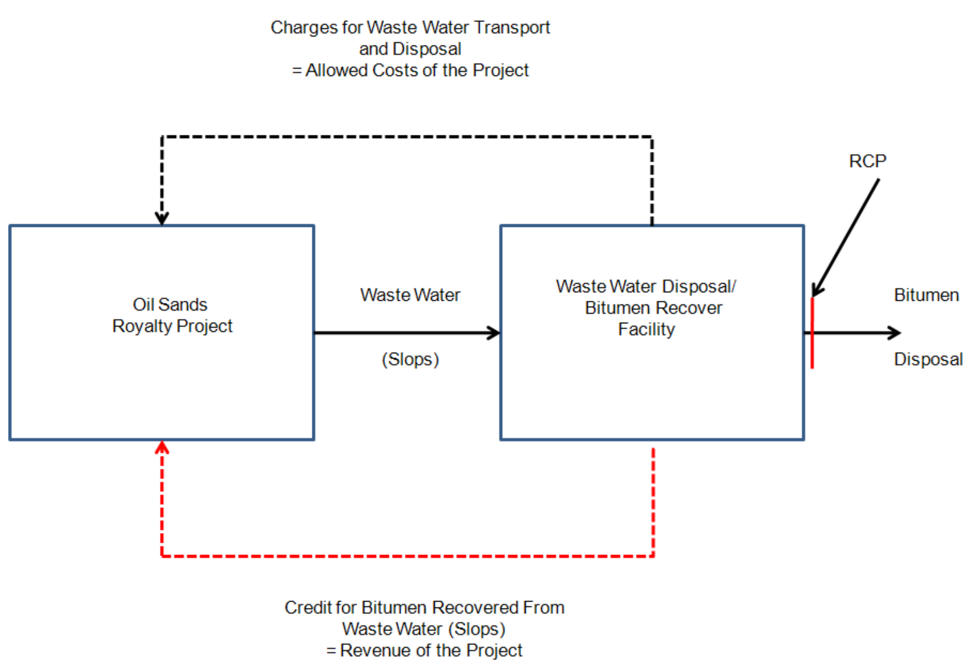
Allowed Costs

- Each Project can deduct allowed costs attributed to production of its raw bitumen.
- Project A, as the owner of the processing facility, can also deduct all allowed costs attributed to processing the volumes of raw bitumen received from both Projects. For Project A, revenues received from Project B for the processing of its bitumen "custom processing fees" are ONPs, which are deducted from allowed costs in calculating the Project's net revenue.
- For Project B, these custom processing fees paid to Project A are an allowed cost.
- If the processing facility is owned by an affiliate of Project B, the NAL cost rules apply to determining the custom processing fees.

4.5.5 Royalty Treatment of Bitumen Recovered from Waste Water

Some details of reporting waste volumes on royalty reports can be found in IB 2013-13.

Figure 5: An OSR Project where Waste Water is trucked to an Off-site, Third-party Treatment Facility for Disposal



Project Output

- In addition to other oil sands products, waste water is trucked from an oil sands Project to an off-site, third-party treatment facility for disposal;
- Bitumen is recovered from this waste water prior to disposal; and
- A credit (reduction) is applied to the disposal charge to reflect the value of the bitumen – which is retained by the operator of the treatment facility.

Royalty Calculation Point

- Treat the off-site disposal facility as a processing plant and establish a royalty calculation point for recovered cleaned crude bitumen at its outlet.
- This would treat the off-site disposal facility in an analogous fashion to an off-site cleaning plant.

Allowed Costs

- Costs of transporting the waste water to the facility and treating it are allowed costs of the oil sands Project (as they occur before the royalty calculation point).
- The credit received for the recovered bitumen from the slops would be revenue for the Project.
- If volumes from other oil sands Projects or non-Projects operation outside the oil sands royalty regime are trucked to the same treatment facility, transportation costs and credits specific to this Project are allowed costs or revenue of the Project.

5. Capital Assets, Engineering Systems and OSR Projects

5.1 Capital Assets or Engineering Systems

Assets are considered capital assets or engineering systems if they

- are used to provide goods and services, rented to third parties, required for administrative purposes, or used for the development, construction, maintenance or repair of other capital assets
- were acquired, constructed or developed for ongoing use, and
- are not intended for sale in the ordinary course of business.

5.1.1 Capital Assets or Engineering Systems included in OSR Projects

Oil Sands Royalty Regulation 2009, Section 14

Capital Assets or Engineering Systems may be included in the Project description of an OSR Project only if they are core or supporting assets.

5.1.1.1 Core or Supporting Assets

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 1(1)(f)

Core or supporting assets represent a special, limited class of capital assets. A core asset is a capital asset without which oil sands or oil sands products could not be physically recovered or obtained pursuant to the OSR Project. A supporting asset is a capital asset necessary for the operation and maintenance of a core asset. An Engineering system is a regularly interactive or interdependent group of assets with a defined common output.

An overhead asset, that is, any capital asset used in connection with the functions and other items described in section 1(1)(b)(i) to (vi) of the OSACR, is not a core or supporting asset and cannot be included in a Project description if it is not solely dedicated to oil sands Project operations.

- A core or supporting asset must meet the OSR Project use threshold defined in the OSRR09 (75%): or, in the case where capital assets or engineering systems are used by two or more Projects that are owned or operated by the same lessees or their affiliates, be almost exclusively used by those Projects, to be included in a Project description.
- The Project use of an asset is defined as, in the Minister's opinion, the sustained use of the asset over its remaining useful life for the purposes of the Project as a percentage of the total use of the asset for all purposes.

Core or supporting assets included in a Project description, which subsequently fail to meet the Project use threshold, will be removed from the Project description.

Where a core or supporting asset or engineering system is included in a Project description, all the costs associated with that asset – for its purchase or construction, and its operation – are allowed costs of the Project in the period in which they are incurred.

5.1.1.2 Partially Includable Assets

Oil Sands Allowed Cost (Ministerial) Regulation (AR 231/2008), Schedule 2 and 3

Generally, a (core or supporting) capital asset or engineering system must either be entirely included in a Project description, or entirely excluded. There are certain capital assets or engineering system, as specified in the OSRR09, which the Minister may partially include in a Project description. These assets are:

- A processing plant owned by both lessees and non-lessees of a Project, which may be partially included in the project description in the proportion that it is owned by Project lessees.
- A processing plant designated by the Minister as an integrated upgrader may be included, in whole or in part, in the description of a Project.
- A cogeneration plant may be included, in whole or in part, in the description of a Project that does not form part of an integrated Project.
- Where a portion of a processing plant designated as an integrated upgrader has been included in a Project description, the equal portion of a diluent recovery unit associated with the processing plant may be included in the Project description.
- Cross-boundary wells, which recover bitumen from the leases of two OSR Projects. A well which recovers bitumen from an oil sands Project and “non-project” leases cannot be included in whole or in part in the oil sands Project description.
- Control system;
- Cooling water system;
- Instrument air system;
- Fire water system;
- Emergency power system;
- Potable water lines;
- Waste water lines;
- Sewer lines;
- Sour water lines;
- Slop oil lines;
- Pipe racks;
- Roads, parking lots, camps and airstrips and associated facilities.

Where a capital asset or engineering system is partially included in a Project description, the costs associated with that asset are allowed costs of the Project in the proportion to which the asset was included in the Project description.

5.1.1.3 Costs of Capital Assets or Engineering Systems in OSR Projects

Where a capital asset or engineering system is included (or partially included) in an OSR Project description, the costs associated with that asset (or portion of it) – for its purchase or construction, and its operation – are allowed costs of the OSR Project in the period in which they are incurred.

Where those costs are incurred in arm's-length transactions, they are valued according to the general cost rules in the OSRR09.

Where they are incurred in non-arm's length (NAL) transactions – i.e., where a capital asset is purchased from or constructed by an affiliate of the Project lessee(s) – the NAL cost rules set out in the OSACR must be applied to value the transactions.

The NAL cost rules are set out in Division 2 of the OSACR, and are discussed in Chapter 6 of these Guidelines.

5.1.1.4 Revenues from Capital Assets or Engineering Systems in OSR Projects

Capital assets or engineering systems included in OSR Project descriptions can generate revenue for the Project, other than through the recovery or production of oil sands products from Project lands, if:

- they are sold or disposed of, or
- they are used for non-Project purposes (i.e., custom processing, where a cleaning plant included in a Project also provides cleaning services for bitumen recovered from non-Project leases) as long as the Project use threshold continues to be met.

In both cases, the revenue received is treated as "other net proceeds" (ONP) of the Project. These ONP reduce the allowed costs of the Project in the period in which they are received. (See section 4.2.4.1 "Types of Revenue").

Where these revenues derive from NAL transactions, the NAL revenue rules must be followed to value these transactions. The NAL revenue rules are set out in section 19 and 20 of the OSRR09, and are discussed in Chapter 6 of these Guidelines.

The chart in section 5.1.2 summarizes the royalty treatment of capital assets or engineering systems and revenues included in the Project description of an OSR Project.

5.1.2 Summary Table: Treatment of Costs and Revenues

<table>
<tr><th colspan="3">Treatment of Costs and Revenues of Capital Assets or Engineering Systems Included in Royalty Projects</th></tr>
<tr><th>Capital Assets or Engineering Systems 100% Included</th><th>Costs</th><th>Revenue</th></tr>
<tr><td>Capital asset included completely in the Project description.

• must be a core or supporting asset – OSRR’09 s.14(2)

• use of the asset must be meet Project use threshold - OSRR’09 s. 1(1)(oo)</td><td>All costs incurred (capital and operating) in respect of the asset included in the Project description are Project costs. (No allocation of Project versus non-project use is necessary.)

• subject to OSACR, s.3</td><td>Any revenues attributable to non-project use of the asset, or its disposition, are “other net proceeds” of the Project.

• OSRR’09 s.23(2)(h)(i)(j)</td></tr>
<tr><th>Capital Assets or Engineering Systems Partially Included</th><th>Costs</th><th>Revenue</th></tr>
<tr><td>NB: Capital Assets or Engineering Systems (other than the exceptions noted below) may NOT be partially included in the Project description.

Exceptions:
(at the Minister’s discretion)

• A proportion of a processing plant owned by lessees and non-lessees of the Project, equal to the proportion owned by the lessees.

• A proportion of a processing plant, designated as an integrated upgrader.

• A proportion of a co-generation unit, taking into consideration the extent of use of thermal energy or electricity and proportionate ownership of lessees – OSRR’09 s.14(8)&(9).

• A proportion of a Diluent Recovery Unit (DRU), equal to the proportion of the processing plant included – OSRR’09 s.14(10)

• Cross-Boundary wells - OSRR’09 s. 14(11)

• Assets or systems listed in OSRR’09 s.14(14)</td><td>Unless an asset can be partially included in a Project description, there can be no allocation of that asset’s incurred capital or operating costs to the Project.

Where the “excluded” asset is owned by the lessee or an affiliate, the cost to the project for services provided must be determined under the NAL cost rules.

Costs (capital and operating) for partly included capital assets are allowed costs of the project in the proportion of the capital asset included in the Project description. I.e., if 50% of a cleaning plant is included in a project, 50% of the costs of that cleaning plant may be allowed costs of the project.</td><td>Any revenues attributable to non-project use, or disposition, of the partially included asset are “other net proceeds” of the Project.

Examples:

• Revenue from processing oil sands products not owned by the lessees in that proportion of the processing plant included in the Project description OSRR’09 s.23(2)(d)(i)

• Revenue from producing thermal energy or electricity in the proportion of the co-generation plant included in the Project description, where that energy or electricity are not used for the Project – OSRR’09 s.23(2)(d)(ii)</td></tr>
</table>

5.2 Solution Gas

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 12(2)(b)(ii), Natural Gas Royalty Regulation, 2017 (AR 211/2016), sections 1(1)(ddd), 14, 15 and schedule 7

Many OSR Projects use natural gas for fuel in their Project operations. In some cases, the fuel gas must be imported into the Project. In other cases, it is obtained from solution gas produced as a result of Project operations.

Solution gas is defined in section 1(1)(rr) of the OSRR09 and in section1(1)(ddd) of the Natural Gas Royalty Regulation, 2017 (NGRR17). Solution gas is not an oil sands royalty product. Gases produced through chemical alteration of crude bitumen through high temperature, high pressure, or a catalyst are considered a royalty substance under the OSRR09. Note that oil sands agreements issued on or after January 1, 2000, grant the rights to oil sands and to the solution gas they may contain.

For some OSR Projects, solution gas gathering and distribution systems are necessary for the production and processing of bitumen as such, they may be allowed costs in the OSR Project. In some cases, the solution gas produced in association with oil sands is used as fuel for Project facilities, and is royalty exempt; in other cases, the solution gas is sold and becomes subject to royalty payable under the *Natural Gas Royalty Regulation, 2009*.

Effective January 1, 2011, the Oil Sands business rules regarding solution gas conservation costs are follows:

1. Solution gas assets necessary for the recovery of crude bitumen that have been approved for inclusion in a Project description for an OSR Project will continue to be included in the Project description and will not be removed and allowed under the NGRR17 under gas cost allowance.
    a) Where the AER has mandated that an OSR Project operator must conserve solution gas, the costs of the solution gas gathering assets may be recognized as OSR Project costs: the gathering of solution gas will be recognized as a necessary process related to the recovery of crude bitumen in those OSR Projects.
    b) Where the AER has mandated that for environmental reasons solution gas must be treated (e.g., sulphur removed) before it is burned on the OSR Project to assist in the recovery of crude bitumen, the costs of treating the solution gas may be recognized as Project costs.
    c) The continued inclusion of the solution gas gathering or processing assets will be subject to the Project use threshold applied to any Project assets. Project use will not take into account gas sales, only the use, if any, of the gas gathering or processing assets by other Projects. It is recognized that after sales of gas occur, the gas gathering or processing assets might be considered to be indirectly facilitating gas sales.
    d) No costs for solution gas gathering and processing assets may be claimed under GCA while those assets are in the OSR Project.
2. Assets that have as their primary purpose the facilitation of solution gas

sales, cannot be included in a Project description for an OSR Project.

a) These assets could include anything up to the sales gas trigger point that has as its primary purpose the facilitation of solution gas sales: sales gas compressors, pipeline tie-ins or processing plants, for example.

b) Such assets will not be approved by the Minister in a Project Description at the time of application for a Project or Project amendment.

c) Such assets that have been included in an existing Project Description will be reviewed by the department and may be removed by a Ministerial amendment.

d) Assets that are removed will be removed at original Project cost, but any return allowance earned to date will remain in the Project.

e) It is up to the operator to claim the costs of these assets under GCA, and the costs cannot be allocated between GCA and the OSR Project.

3. All solution gas produced from the OSR Project leases and consumed on-Project will continue to be royalty-exempt as per section 15 of the *Natural Gas Royalty Regulation, 2017*.

   a) Gas that is not permanently removed from the OSR Project, flows back to the Project from a sales asset described in paragraph 2, and is consumed on-Project, will be considered royalty-exempt, and no costs associated with that asset will be charged to the Project.

4. There will be no solution gas sales volume or timing threshold (e.g. no “three month rule”).

   a) Any solution gas that is not consumed on Project and is permanently removed (“exports”) from the Project will be subject to the Natural Gas Royalty Regulation, 2017.

   - The applicability of the royalty exemption to minor, isolated exports of solution gas will be dealt with by Gas Royalty.
   - Measurements and reporting of solution gas exports will be dealt with between the Project operator, the Petroleum Registry of Alberta and Gas Royalty.
   - Valuation for gas royalty purposes of solution gas exports will be dealt with under the Natural Gas Royalty Regulation, 2017.
   - The royalty treatment of other gas substances like sulphur recovered from solution gas will be dealt with by Gas Royalty.
   - The eligibility of non-royalty exempt solution gas for any royalty incentive programs is a matter for Gas Royalty.

   b) The treatment of solution gas assets will not be linked to a particular solution gas sales volume, or to sales occurring over a specific period of time.

   - The only criteria for the inclusion of a solution gas asset in an OSR

Project will be as set out in 5.2.1 and 5.2.2, above.

5. For the purpose of determining allowed costs, any non-arm's length transfers of solution gas from an OSR Project to other OSR Projects operated or owned by affiliates will be considered dispositions of solution gas.

   a) The cost of the gas to the importing OSR Project will be based on 80% of the Alberta Gas Reference Price (ARP) when sold in a raw or unprocessed gas state and at 100% of ARP when gas is processed and sold as residue gas.

5.3 NAL Pipeline Services

Oil Sands Allowed Cost (Ministerial) Regulation, (AR 231/2008) sections 10(4) to 10(8)

Pipelines for transporting bitumen (or blended bitumen) to market—that is, from a Project's RCP to the point of disposition—are called non-basic pipelines because the service they provide is not a "basic service" needed for the production of clean crude bitumen. Similarly, pipelines transporting diluent to an OSR Project are non-basic pipelines.

Under the OSRR09, non-basic pipelines cannot be included as part of an OSR Project description. However, charges for the use of such bitumen or blended bitumen pipelines can be deducted, as handling charges, in calculating the unit price of the oil sands product. (See section 5.3.1, "Calculating Costs for Non-Basic Pipeline Non-Arm's Length Services") Charges for the use of a diluent pipeline can be included in the "cost of diluent" for the OSR Project. The total charge that can be claimed is the sum of the operating costs plus the capital costs per m3 of capacity. Both costs are based on the portion of pipeline throughput that pertains to the Project.

The cost of "line fill" oil (or diluent) required to be provided by the Project owner can enter into the calculation of non-basic pipeline costs (see section 5.3.2 "Line fill Costs").

5.3.1 Calculating Costs for Non-Basic Pipeline Non-Arm's Length Services

The calculation of costs for a non-basic non-arm's length pipeline depends on whether or not a fair market value (FMV) can be established for the use of the pipeline:

- When a pipeline is owned by the OSR Project owner or by an affiliate, and the Minister can establish a FMV for the pipeline services (according to Section 12(1)(a)(b) of the OSACR), the allowed cost is the lesser of the amount charged to the Project and the FMV.
- If the Minister cannot establish a FMV, the allowed cost is the lesser of the amount charged to the project and the cost as determined by a cost-of-service calculation.

5.3.1.1 Allowed Costs Based on Fair Market Value

If the non-basic NAL pipeline has a regulated tariff, that tariff represents the FMV of pipeline services.

When there is no regulated tariff, a published tariff charged by the pipeline owner may be used if the following conditions are met:

- The tariff is also paid by shippers who are not affiliated with the pipeline owner.
- Tariff is just and reasonable.
- All tariff charges are published.
- The tariff is fair and non-discriminatory.
- The pipeline is subject to complaints-based regulation.

When a pipeline tariff is not available, or when no comparable service exists, the FMV of non-basic pipeline services can be approximated by the weighted average of prices paid by shippers who are not affiliated with the pipeline owner. The following conditions must be met:

- The pipeline is subject to complaints-based regulation.
- The weighted average price is fair.
- At least two-thirds of the volume of oil sands product shipped on the pipeline is owned by shippers who are not affiliated with the pipeline owner.

What is Complaint-based Regulation?

> A pipeline is subject to regulation on a complaints basis if a customer or potential customer can, by filing a complaint with a regulatory authority, initiate a review and modification of the terms of the pipeline service and charges. In Alberta, that means that you are designated as a common carrier subject to complaints.

5.3.1.2 Allowed Costs Based on Cost-of-Service Calculations

In the case of a non-basic pipeline providing transportation service to oil sands products from a Project, if a FMV cannot be reasonably determined for the transportation service, the pipeline charge allowed for a unit price deduction will be the lesser of:

(a) the amount charged to the Project; and

(b) the cost of service (COS).

The COS calculation methodology for non-basic pipelines is as set out in the OSACR, and described in Section 6.2.2 and Appendix J of these Guidelines.

However, the rate of return on capital (RORC) is not the long-term bond rate (LTBR), as it is for all other COS assets. It is based on a deemed debt/equity ratio, and a pipeline cost of capital rate determined by the NEB.

As for other COS assets, if a non-basic pipeline has been in service prior to 2011, and if the rate of depreciation charged on the pipeline was acceptable to the Minister, that rate may continue to be charged in the COS calculation (rather than the specified 4% rate) until such time as a capital addition that is greater than 10% of Cumulative Capital Cost (CCC) is made.

- Where the pipeline has more than one owner the COS calculation is based on a Project owner's share of the capital investment in the pipeline and its share of the pipeline's operating costs. The Project owner's share of operating costs is determined by its proportion of throughput during the year.
- Example 1 shows the COS calculation for a non-basic pipeline by a Project owning 50% of the line and 50% of total throughput.
- The following formula is used to calculate the allowed rate of return on capital (RORC).

Note

> The non-basic pipeline RORC calculation is the only COS calculation that does not employ the LTBR as the RORC.

$$\text{RORC} = \left(\text{Deemed Debt Percentage}\right)\left(\text{Deemed Cost of Debt}\right) + \left(\text{Deemed Equity Percentage}\right)\left(\frac{\text{Deemed Cost of Equity}}{\text{(1-Deemed Corporate Income Tax Rate)}}\right)$$

Deemed Debt Percentage = 45%

Deemed Equity Percentage = 55%

Deemed Cost of Debt = Long-Term Bond Rate plus 1%

Deemed Cost of Equity = the annual multi-pipeline rate (for group 1 pipelines), as published by the National Energy Board (NEB).

For more information on NEB publishing the return on equity (ROE), please refer to Oil Sands Information Bulletin 2017-01.This formula incorporates the deemed corporate tax rate and so yields a pre-tax weighted average cost of capital. Since corporate income taxes are included within this formula, no additional provision for corporate income taxes should be included in the pipeline's revenue requirement.

The capital structure may be revisited at the Minister's discretion.

The deemed corporate tax rate will be updated when Provincial or Federal rates change

Example 1

Assumptions:

The pipeline is in its 5th year of

Calculation:

Owners capital cost is

operations.

Cumulative capital cost is $90 million;

One owner's share is 50%;

The calculated rate of return on capital (RORC) in year 5 is 12.92%

Total throughput in year 5 is 55 million barrels, of which the owner owns 50% (27.5 million barrels)

Total capacity/year = 60 million barrels

(50% of $90 million) = $45 million;

Depreciation charge is
($45 million / 25 years) = $1.8 M/year;

Average capital employed in year 5 is (initial capital + end capital) / 2 = ($37.8 million + $36.0 million) / 2 = $36.9 million.

The per barrel capital charge would be equal to the average capital employed multiplied by the rate of return, plus the Period depreciation, divided by throughput:

($36.9 million * 12.92%) + $1.8 million/27.5 million barrels= $0.239/barrel

Capital Unit Charge = 0.239/Barrel

Additionally, the COS would include the Project's share of operating costs, based on throughput (in this case 27.5 / 55 = 50%).

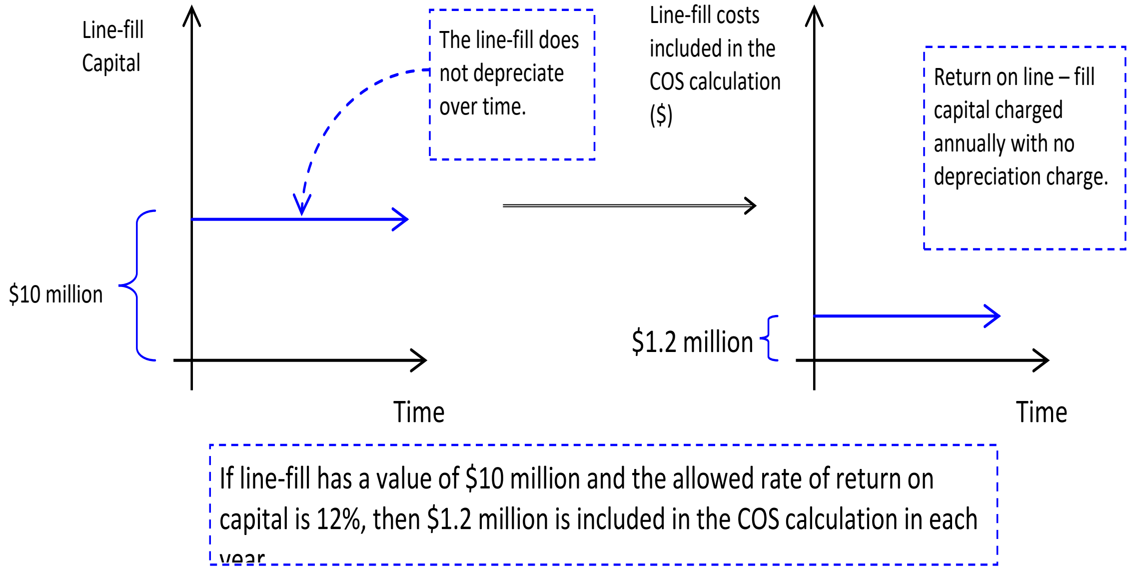
Where an owner's throughput exceeds its share of ownership, additional arm's length charges can be part of the COS. Where an owner allows another party to use part of its capacity, ONP will accrue.

5.3.1.3 Line Fill Costs

In addition to the COS as calculated above, Project owners may include a rate of return on the initial cost of the oil volumes purchased to "fill" the pipeline in their COS calculation. This return rate (RORC) is the same as the return rate allowed for in the cost-of-service calculation. The following cost rules apply:

- Companies paid royalties on all inventory volumes as at December 31, 2008. The value of the line fill is its purchase cost, not its market value.
- The COS calculation does not include the original purchase cost. Only a return on capital (i.e. the original purchase cost of the line fill) is allowed.
- Revaluations of line fill costs are not allowed.

Figure 5: Calculating line fill costs



5.4 Cogeneration Plants

Oil Sands Royalty Regulation, 2009, (AR 223/2008) Section 1(1)(e), Section 14(8) and (9), Section 23(2)(d)(ii)

5.4.1 Cogeneration Cost Allocation Rules

Cogeneration facilities use a fuel source, often natural gas, to produce both thermal and electrical energy. The useful thermal energy is often in the form of steam, and the units are also known as Combined Heat and Power (CHP) units.

Cogeneration facilities will only be included, in part, in the Project description in the context of non-integrated Projects. For integrated projects, co-generation facilities will be included as part of the integrated shared operations and costs will be allocated accordingly.

Determinations of allowed costs for cogeneration units requires an allocation of eligible costs (including fuel costs, asset costs and ongoing maintenance costs), to the steam and electricity production systems.

The following represents a modification and re-organization of the cogeneration cost allocation rules which existed in the Oil Sands Royalty Guidelines, 2006. There are only minor changes to the cost allocation rules, and they are listed below:

- There will be no COS method applied to the electricity component of the cogeneration system. Electricity will be valued by a market based FMV method.
- The efficiency of a cogeneration unit for the purposes of the Fuel Charged to Steam (FCS) calculation will always be 85%, eliminating the detailed calculation required in Section 5.3.1.3.1 of the Oil Sands Royalty Guidelines, 2006.
- Cost rules for sales of cogeneration plants as described in, Section 5.3.6 of the Oil Sands Royalty Guidelines, 2006, no longer apply.

5.4.2 General Allocation and Cost Determination Steps

1) Determine the portion of input fuel costs which are attributable to steam production vs. electricity production:
   (a) Fuel consumed for process steam generation vs. total fuel consumed by the cogeneration unit.
   (b) Fuel charged to steam (FCS) calculation, based on the measured useful energy in the process steam used for heating purposes, assuming 85% thermal efficiency of a boiler or heat recovery steam generator (HRSG) unit.
   (c) The value of input fuel to the cogeneration system will be based on the price paid in arm's length transactions, or the FMV of the fuel as determined by the Minister.
2) Allocate components which are shared between the cogeneration units and other units
   (a) Allocate components such as water treatment plants which provide service to both the cogeneration units and other units. The portion of the costs which are attributable to the cogeneration unit will be determined, then that portion eligible to the cogeneration unit will be divided between steam and electricity.
3) Allocate the dedicated components of the cogeneration system into electricity only, steam only, and shared categories.
   (a) Final allocation of components must be approved by Oil Sands Division.
   (b) Components which function primarily to provide useful heat will be allocated to the steam portion, components which function primarily to provide electricity will be allocated to the electricity portion of the Cogeneration system.
   (c) Eligible maintenance and repair costs on a component will be considered an operating cost of that component.
   (d) Shared components will be allocated based on the fuel charged to steam vs. the fuel charged to electricity calculation.
4) Allocate the steam use by the OSR Project vs. non-project royalty.
   (a) Measured steam use or engineering design steam use
5) Allocate the electricity use by OSR Project vs. non-royalty project.
   (a) Measured electricity use or Measured sales from the unit
6) Value the NAL electricity and steam – See section 5.4.3 "Valuing NAL Electricity and Steam" below.
7) Allocation cost treatment for Project and non-project systems – See 5.4.3.3 – "Cost Treatment for Project and Non-Project Systems" below.

The cost allocation for Project and non-Project Systems can be found in the discussion paper in Appendix J.

5.4.3 Valuing NAL Electricity and Steam

The value of NAL electricity and steam must be determined when:

- They are provided to an OSR Project by a non-project asset (Allowed Cost)
- They are provided by Project assets for non-project uses (ONP Owed to Project)

5.4.3.1 Fair Market Value for Electricity

The FMV of electricity for a given month will be the Average Pool Price reported by the Alberta Electric System Operator (AESO) for that month. It will be the FMV of all electricity consumed or sold at NAL produced by a cogeneration unit in that month. Any electricity purchased or sold at arm's length will be valued at that arm's length price.

5.4.3.2 Steam – Cost of Service Calculations for Steam Systems

The value of NAL steam that crosses royalty Project boundaries will always be calculated using a COS methodology.

- As per the standard COS rules, any capital or operating cost brought into the calculation must meet the same criteria as an allowed cost to an OSR Project.
- COS calculations involve the calculation of a capital unit charge and an operating unit charge. When calculating the capital unit charge for cogeneration units, the allowed annual capital charge is divided by the greater of:
  - 75% of the capacity rating of the steam system
  - The actual throughput of the steam system

The Operating unit charge is calculated based on actual throughput.

The COS will be calculated using the eligible capital and operating costs, including fuel, allocated to the steam system, with a 4% annual depreciation rate and a RORC of LTBR.

5.4.3.3 Cost Treatment for Project and Non-Project Systems

- If a system is included as a Project asset
  - The eligible costs of the system, including fuel, are fully included as allowed costs, and the ONP due to the OSR Project by NAL non-project use of the asset must be calculated.
- If the system is not included in the Project
  - The value of electricity and steam provided to the Project become allowed costs of the Project
- If the system is partially included in the Project
  - The value of electricity and steam provided to the Project become allowed costs of the Project

5.4.4 Fuel and Component Allocations for Cogeneration Systems

The following is not meant to be an exhaustive list of cogeneration facilities that are, or may be present in OSR Projects, but serves as a guideline for the two systems that are most common at this time. Each cogeneration facility should provide plans including component allocation to the steam, and power systems of their cogeneration facility to the Oil Sands Operations, and a detailed component allocation methodology for each system will be developed.

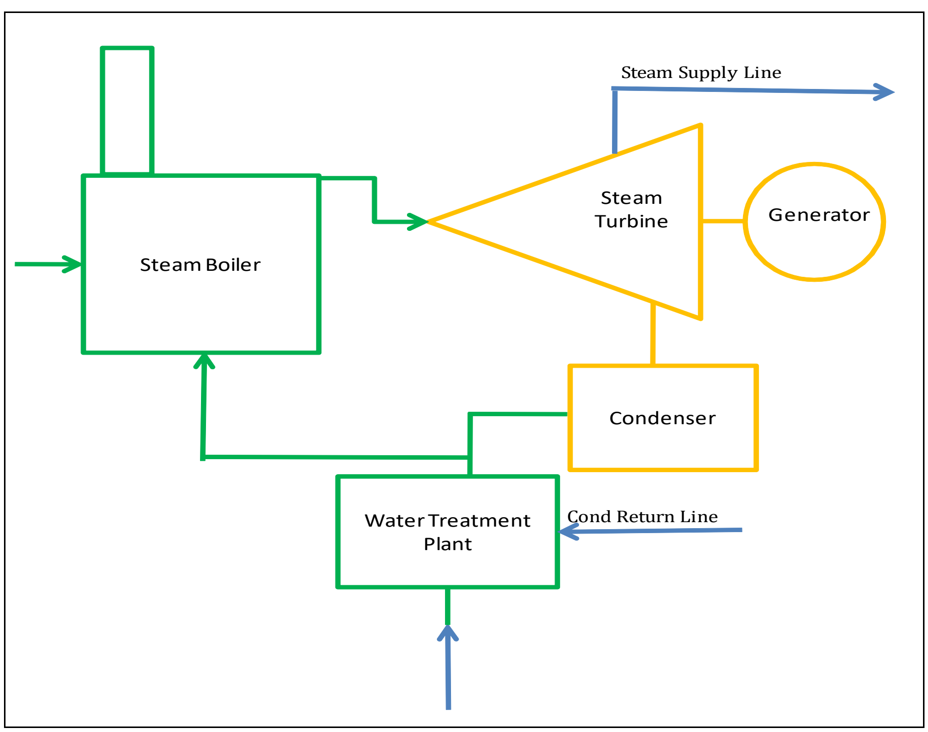
5.4.4.1 Non-Gas Turbine Based, Combined Heat and Power (CHP) system

A traditional "Combined Heat and Power Plant" (CHP) would use a conventional steam boiler (BLR) and a steam turbine (ST) with an extraction valve to provide process steam as well as generate electricity, as simplified in Example 1 below:

In Example 1, it is implicit that all the water from the treatment plants feeds the steam boiler, and all of the steam boiler output is sent to the principal components of the CHP unit (steam turbine and on).

In a more likely case where only a portion of a given water treatment system, and/or steam boiler output is input to the CHP, it is that portion of the water treatment system, and steam boiler costs which are allocated to either the heat, or power systems of the CHP unit.

Example 1



1. Fuel Energy Allocated to Process Steam

- The fuel energy allocated to process steam will be the net useful energy measured or calculated in the process steam divided by 0.85 to account for the boiler efficiency. This energy is then divided by the energy density of the fuel to get the net fuel quantity charged to the steam generating system.

Fuel Energy = [(Process Steam Energy – Process Return Energy)/0.85].

Fuel Quantity Charged to Steam (FCS) = Fuel Energy / Energy Content of Fuel

Fuel Electricity = Fuel Boiler – Fuel Charged to Steam

2. Costs Allocated to the Steam System

- Process steam valves or lines connecting the major components of the CHP Plant to the OSR Project (primarily a steam supply line from the steam turbine to the OSR Project and a condensate return line from the OSR Project to the water treatment plant or the condensate storage tank)
- Any maintenance costs associated with these pieces of equipment
- Any Costs before where the steam goes to steam turbine

3. Costs Allocated to the Electricity System

- Steam turbine (ST), ST governor valves, ST bypass valves, bypass piping, condenser, generator, substation and any transformers or transmission interconnections only used by the cogeneration unit
- Any secondary equipment associated with these major pieces of equipment
- Any maintenance performed directly on these components

4. Shared Costs Allocated on the basis of relative Fuel used between Electricity and Steam

Boiler feed water (BFW) system, high pressure steam line (main steam header) and boiler **feed** water pumps (BFW PMP)

5. Costs Shared Between the Cogeneration System and Other Uses

The portion of water treatment plants deemed to be used by the cogeneration system is eligible to be allocated by this method. This will involve engineering consultations for each project.

5.4.4.2 Gas Fired Turbine Combined Heat and Power Systems

1. Fuel Energy Steam = Useful Energy in the Process Steam / 0.85.
   - Fuel Charged to Steam (FCS) = Fuel Energy Steam / Energy content of fuel
   - Fuel Charged to Power (FCP) = Total Fuel - FCS
2. When capital, operating, and other annual non-fuel-related cost allocations are split between the steam and electricity generating functions of the plant, the following rules apply:
   - All capital, operating and annual non-fuel costs incurred upstream of the point where hot gases are transferred to the HRSG are allocated to

electricity. That is, the gas turbine and generator are allocated as electricity costs; the HRSG is not.

- All capital, operating and annual non-fuel costs incurred downstream of the point where hot gases are transferred to the HRSG are allocated to steam. That is, the HRSG is allocated as steam-related costs; the gas turbine and generator are not.

5.4.5 Determining Capacity for a Steam Generating Unit

Note

> Additional information, and examples of the allocation of cogeneration and steam generation costs, can be found in Appendix J.

5.5 Custom Processing

If a Project asset is used to provide NAL custom processing services to other OSR Projects, the NAL rules apply. (See Chapter 6 – “Non-Arm’s Length Transactions and Affiliates”.) Also continued inclusion of Project assets in the Project is subject to project use threshold.

5.6 Hedges

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 19(6)(b)

Hedges are physical or financial arrangements entered into to reduce the risk of investments or other financial transactions. They may use contracts for physical delivery or financial derivatives to avoid future price fluctuations and to reduce risk.

Revenues, payments, and costs related to transactions entered into to hedge price risk are generally not included in calculations under the OSRR09. However, there are exceptions where these amounts are included:

- Contracts of insurance, surety, guarantee or indemnity;
- Contracts for the future sale or purchase of a commodity or currency, where the delivery or receipt of the commodity actually occurs under the terms of the contract, whether the price is determined in advance or is indexed to a particular market price or financial instrument.
- Contracts that hedge price or currency risk specifically in relation to allowed costs of a Project. In this case the Project operator must notify the Department of the hedging policy. Hedges must relate to specific Project costs, and the gains or losses and the costs associated with the hedging transaction must be clearly documented. Project-related commodities, goods or currency must be clearly identified.

Examples:

- A Project guarantees its future price for bitumen by entering into a forward contract to sell at a fixed price, and delivers bitumen under the terms of the contract. Here the revenues from the forward sale are included in the royalty calculation.

- If the Project undertook to guarantee its future price for bitumen by selling on the spot market but entering into a financial swap contract with a counterparty, the spot market revenues would be relevant for royalty calculation, and no costs, gains or losses related to the hedge arrangements would be considered – as no physical delivery occurred under the swap contract.
- Costs of hedging currency risk related to the purchase of equipment from abroad for a Project can be allowed costs of a Project.

5.7 Research

Since research provides an important contribution to the continued competitiveness of Alberta's oil sands, certain research costs can be claimed as allowed costs.

5.7.1 Cost Rules for Research

Oil Sands Allowed Costs (Ministerial) Regulation, (AR 231/2008) – Item 56 of schedule 1 and Item 56 of schedule 1.1

To be eligible for deduction as allowed costs, research costs must comply with the following rules:

- The research must have a specific, practical, Project-related application for a single Project.
  - Research can be undertaken at off-site labs as long as it is directly related to Project activities.
- Research costs must be directly attributable to the OSR Project.
  - The scope of allowable research costs is determined by the Project description. For example, if an approved Project includes an upgrader, research costs that are directly attributable to that upgrader may be eligible.
- Research costs must be incurred by or on behalf of the Project owners.
- Research costs must be incurred and paid after the date on which the Project was approved.
  - Research costs incurred before a Project's effective date may be included in determining the Project's PNCB. (See section 2.3.11 – "Prior Net Cumulative Balance".
- Claimed research costs must reflect an actual financial transaction that is supported by documentation.
  - Project operators should be prepared to provide sufficient information to support the claim of eligibility for research costs.
- Only net research costs are allowed.
  - With the exception of income tax reductions, all credits or discounts that reduce actual research costs must be deducted from the Project's allowed

costs. This includes credit for research received from other programs in Alberta or from any other jurisdiction in which the research is recognized. (If such credits or discounts were not recognized, the benefit would be counted twice.) Refer to section 7(1)(c) of the OSAC Regulation.

- Project owners, who recover research costs from other industry participants, must include the recovered amounts as "other net proceeds" (see section 4.2.4.1 – "Types of Revenue"). This ensures that the research costs are only counted once. Non-basic research costs may be eligible both as deductions against royalties under the OSRR09 and as deductions against escalating rental payments under the Oil Sands Tenure Regulation. Note, however, that the royalty and escalating rental deductions are not required to be applied proportionally to the same leases.

5.7.2 Examples of Allowed Research Costs

The following types of costs may be eligible as allowed costs:

- Market research related to Project planning and design.
- Costs incurred to support a specific consortium research activity that has direct applicability to the OSR Project.
  - Funding a specific, university-based project in order to receive the research data and conclusions is an example of an eligible consortium research activity.

5.7.3 Examples of Research Costs That Are Not Allowed

- Research-related management costs and membership fees.
- Costs of research without specific practical application to the OSR Project.

5.8 Cross-Boundary Wells

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 14(11)

Cross-boundary wells are crude bitumen production wells that have been drilled across the boundaries of adjacent OSR Projects. Usually, the same operator operates both Projects. Portions of the wells are open to, and produce from, the same reservoir in both Projects.

Note

> The term cross-boundary wells only applies to wells that are split between OSR Projects but reside entirely within OSR Projects. Wells that produce both from Project and non-project lands are not "cross boundary wells" and cannot be included in any OSR Project. To clarify: A well that produces partially from lands that do not form part of any OSR Project is not a cross boundary well and cannot be included in any Project. The well is considered

to be a non-project well in its entirety.

The amalgamation of any affected OSR Projects, where that could be achieved, would be the best solution to this allocation issue.

Where amalgamation is not feasible, the Department will accept the allocation of production, costs and revenue related to cross-boundary wells based on the proportion of producing interval in each Project.

The allocations between two Projects A and B should be calculated as follows:

> **Project A** Allocation Factor = Length of producing interval on Project A / Total length of producing interval;
>
> **Project B** Allocation Factor = Length of producing interval on Project B / Total length of producing interval;

If 75% (for example) of the producing interval lies on Project A, the Department will assume that 75% of the production came from Project A and 25% came from Project B, disregarding any reservoir heterogeneities and actual fluid flow behaviour – unless there is clear evidence to refute this assumption.

> **Project A** Well Capital Cost = Total Well Capital Cost * Project A Allocation Factor;
>
> **Project B** Well Capital Cost = Total Well Capital Cost * Project B Allocation Factor;

In the case of “monthly operating costs” (“OPEX”), the following methodology should be used:

> Project A OPEX =
>
> Aggregate OPEX * Monthly Overlapping Well Production * Project A Allocation Factor;
>
> Project B OPEX =
>
> Aggregate OPEX * Monthly Overlapping Well Production * Project B Allocation Factor;

Where

> Total Monthly OPEX = Project A Monthly OPEX + Project B Monthly OPEX;
>
> Total Monthly Production = Project A Monthly Production + Project B Monthly Production;
>
> Aggregate OPEX = Total Monthly OPEX / Total Monthly Production;

Operators intending to drill cross-boundary wells should apply to the Department for an amendment to the Project description to include these wells, prior to drilling. Operators should include with their application supporting engineering and geologic information to justify the proposed allocation factors.

Cross-boundary wells, if approved in OSR Projects, are listed explicitly as part of the Project, and each time a new cross-boundary well or set of new cross-boundary wells are to be drilled it will require an amendment to all affected OSR Projects. Additionally, if a unique well identifier of a cross-boundary well changes due to timing of drilling or recompletion of the well or any other circumstance, after its approval in an OSR Project, an amendment to the affected Projects is required in order to update the correct wells in the Project. Otherwise these cross-boundary wells not listed in the Project description will be subject to conventional royalty and costs of the wells will not be allowed into any OSR Project until such time as they are properly applied for and approved.

5.9 Wells with Surface Locations off Project Lands

A situation can arise where a well is drilled from a surface location that is not on Project lands, however the entire producing interval is within the Project. This situation is not the same as a cross boundary well, where the producing interval is split over more than one Project. Wells with surface locations off Project Lands may be eligible for inclusion in a Project, but an amendment to the existing Project is required. Once the wells have been drilled, an operator may submit an application to Alberta Energy to request inclusion of the wells in an existing Project, and must provide supporting data demonstrating that the entire producing interval of the well is within the Project boundaries.

6. Non-Arm's Length Transactions and Affiliates

The following rules and definitions apply in the interpretation of the OSRR09 and the OSACR. They may or may not be applicable in other situations.

6.1 Non-Arm's Length Transactions

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 2

As noted in Section 4.2.5.2 of these Guidelines, when oil sands products are disposed of in non-arm's length transactions, the Minister may need to determine the fair market value of those products to calculate their unit price.

Similarly, the capital assets, goods and services required to operate an approved oil sands Project may be provided by an independent third party or by an affiliate. If an affiliate is involved, the use or acquisition of the asset, good or service is considered to be a non-arm's length transaction, and must be valued in accordance with approved non-arm's length cost rules.

These rules for non-arm's length cost transactions specify the amount that can be charged to a Project. The purpose of these rules is to ensure that the transaction is valued in a manner that does not inappropriately reduce royalty payable to the Crown. The flowchart in Section 6.3: "Cost rules (simplified) for non-arm's-length good, service, or asset acquisitions", shows how the rules are applied.

Similarly, where assets of a Project are disposed of, or provide services, to an affiliate, the resulting Other Net Proceeds revenue must be established according to the appropriate non-arm's length revenue rules. The purpose of these rules is to ensure the transactions are valued fairly, in a manner that does not inappropriately reduce royalty payable to the Crown.

6.1.1 Definition of Affiliate

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 2(1) and 2(2)

A person is considered affiliated with another person if the criteria outlined in subsection 1206(5) of the Income Tax Regulations apply. However, in making this determination, paragraph 1206(5)(a) shall be read as if it were replaced by the following:

- a person and another person (in this paragraph, referred to as "that other person") are connected with each other if:
  - the person and that other person are not dealing at arm's length,
  - the person has an equity percentage in that other person that is not less than 10%, or
  - where the person is a corporation, the corporation and that other person are linked by another person who has an equity percentage in each of

them of not less than 10%.

Persons are not dealing at arm's length with each other if they would not be considered to be dealing at arm's length under the Income Tax Act (Canada).

6.1.2 Definition of Non-Arm's Length Transaction

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 2(3)

A transaction is considered to be a non-arm's length transaction if any one of the following holds:

a) a party to the transaction is affiliated with any other party to the transaction,

b) any party to the transaction is in a position to compel any other party to the transaction to enter into the transaction,

(Here, "compel" means to compel only in terms of normal business transactions; it does not imply exercising any illegal compulsion)

c) the consideration for any party under the transaction is in whole or in part based on or tied to

i. any other contractual or other obligation with another party to the transaction, or

ii. any consideration under a contractual or other obligation described in sub clause (i), or

d) only one party is involved in the transaction, i.e.; in the case of an integrated oil sands operation - a mine and an adjacent upgrader - there may only be one person (the corporate owner) that is dealing with themselves.

Any transaction to which the only parties are the Crown and another party is considered to be an arm's length transaction.

6.1.2.1 Ministerial Determination of Non-Arm's Length Transactions

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 2(4) and 2(5)

If a Project operator is concerned that a particular transaction related to the Project may be considered to be a non-arm's length transaction, they may apply to the Minister (under section 2(4)), for a determination that the transaction is (or is not) an arm's length transaction.

- The Minister may determine that the particular transaction described by the Project operator is or is not occurring on an arm's length basis.
- The Minister may also make this determination on his own initiative, without application by a Project operator.

A transaction will be considered an arm's length transaction if it is not a non-arm's length transaction under section 2(3) of the OSRR09, or if it is determined by the Minister to be an arm's length transaction.

The Minister may revoke such a determination if the circumstances of the transaction on which the Minister based the determination change.

The Department will provide written notice to the Project operator of any determination, or revocation of a determination, made under section 2, and the effective date of that determination or revocation.

Note

> A determination that a transaction is (or is not) a non-arm's length transaction will affect how any costs or revenues arising out of that transaction must be reported for royalty purposes, beginning with the reporting Period in which the effective date of the determination falls.

6.2 Valuing Non-arm's Length Costs

The rules for the valuation of non-arm's length costs are set out in Division 2 of the OSACR. These non-arm's length cost rules also apply in the calculation of "handling charges" as defined in section 32(1)(a) of the OSRR09, and "BRC" and "GRC" as defined in section 5(3) and 5(4) of the BVMR.

When valuing the cost of a good, service, or asset provided to an OSR Project in a non-arm's length transaction, we need to determine whether the item provided is a capital asset or engineering system, or whether the service provided is a "basic service".

Definition:

A basic service is a service provided to a Project:

1) without which oil sands or oil sands products could not be physically recovered, or
2) necessary for the operation or maintenance of a core or supporting asset of the Project,

using a core or supporting asset that is not included in the Project.

For example, where a Project produces clean crude bitumen using a cleaning plant that is not included in the Project description, the "cleaning" is a basic service provided to the Project.

Note:

For the purposes of valuing non-arm's length costs:

1. the provision of thermal energy, and the transmission and distribution of electrical energy are services, and
2. electricity is a good.

6.2.1 Where a Fair Market Value can be determined

Oil Sands Allowed Costs (Ministerial) Regulation (AR 231/2008), sections 12(1)(a) and 13

In a case where the Minister is satisfied that a fair market value can be determined for:

1. the amount of a cost, where the cost is <u>not</u> incurred for the acquisition of a

capital asset, or

2. the charge for a service that is not a basic service,

then the allowed cost or charge is the lesser of:

1. the amount charged to the Project, and
2. the fair market value determined by the Minister.

Note:

For the purpose of establishing a fair market value for a good or service (other than pipeline transportation), the Minister will generally consider, without limitation, a published index of prices for the comparable good or service, a price for the comparable good or service determined under a regulation of the Government of Alberta or Canada, or an average of arm's length prices for the comparable good or service.

In setting a fair market value for a non-arm's length pipeline transportation cost, the Minister may also, without limitation, consider the tariff (or average charges) for the pipeline service under consideration, if:

1. the tariff is fixed or approved for the transportation service by a regulatory authority,
2. the tariff is subject to regulation by complaint, is published, reasonable, no-discriminatory, and generally agreed to by arm's length customers, or
3. the pipeline is subject to regulation by complaint, and the charges are reasonable, and 2/3 of the volumes are transported at arm's length.

In a case where a cost is incurred for the acquisition of a capital asset, and the Minister is satisfied that a fair market value can be determined for the asset, the allowed cost is the least of:

1. the amount charged to the Project for the asset,
2. the fair market value of the asset, and
3. the net book value of the asset.

In each case including any costs of transporting the asset to the OSR Project.

Definition:

The "net book value" of the asset is the undepreciated portion of its capital cost to the person providing the asset, according to the records of the Department. If the Department has no records of the asset, then it is according to the books of the person providing the asset.

6.2.1.1 Transfer of Assets between Affiliated OSR Projects

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 19(4)

An operator or lessee of an OSR Project may move an asset from one OSR Project to another, where the lessees of either OSR Project are the lessees of the other OSR Project or are affiliated with the lessees of the other Project.

When a capital asset is transferred, it should be removed from the description of the originating OSR Project and added to the description of the receiving Project. This will require an application to amend the OSR Project.

To record this transaction, the originating OSR Project must report a consideration (ONP) for the asset and the receiving OSR Project must report a cost.

In such a case, the Minister may determine (under section 19(4)), that the fair market value of the asset for ONP by the originating OSR Project equals the amount of the allowed cost for the asset of the receiving OSR Project.

6.2.2 Where a Fair Market Value cannot be determined, or a "basic service" must be valued

Oil Sands Allowed Costs (Ministerial) Regulation (AR 231/2008), sections 12(1)(b) and 12(2)

In a case where the Minister has determined that a fair market value cannot be determined for a good or service provided to the project, where the service is not a basic service and is performed without using a capital asset, the allowed cost is the lesser of:

1. the amount charged for the good or service, and
2. the actual cost to produce the good or provide the service incurred by the provider.

In a case where the fair market value of a service provided using a capital asset cannot be determined, or where the service provided is a basic service, the allowed cost is the lesser of:

1. the amount charged for the service, and
2. the cost of service of the provider of the service.

6.2.2.1 Cost of Service Overview

Oil Sands Allowed Costs (Ministerial) Regulation (AR 231/2008), sections 12.1 to 12.7

For cost of service calculations, the OSACR defines the cost of service methodology. For details and examples related to the cost of service methodology and calculations, please refer to the "cost of service calculations in Appendix J of this guideline. The following are some main features of the cost of service calculation.

Cost of service assesses the costs incurred by the provider of the service and its calculation includes a capital component and an operating component.

Cost of Service

If an asset does not have a readily identifiable capacity, cost of service is equal to the sum of the "annual capital charge" and the "annual operating charge" of the asset. These terms are elaborated upon, below.

If an asset has a readily identifiable capacity, cost of service is equal to the unit charge of the asset multiplied by the number of units produced for a Project.

In circumstances where it is not practical to calculate a cost of service, the Minister may prescribe an amount based on engineering or economic calculations.

Unit Charge

$$\text{unit charge} = \left[\frac{\text{annual capital charge}}{\text{units of capacity}} + \frac{\text{annual operating charge}}{\text{throughput}} \right]$$

- annual capital charge = depreciation charge + return on capital
- units of capacity = the greater of 75% of the expected capacity or actual measured Throughput.
    - For some specific assets where oversizing is a good engineering practice, the unit of capacity will be defined as actual throughput. Those assets are: raw water treatment, steam generation, and boiler feed water treatment. (A pipeline does not fall into this group of assets.)
- annual operating charge = annual operating costs incurred
- throughput = annual units produced/processed/transported by the asset

Cumulative Capital Cost

To calculate the depreciation charge, we first calculate the “Cumulative Capital Cost” (CCC). The CCC is reviewed each year, and notionally is the sum of the costs incurred to construct/acquire an asset, plus the sum of the costs to construct/acquire significant capital additions to that asset, less the sum of the costs that were previously incurred to construct/acquire those portions of the asset that have been retired.

For an asset commissioned on or after January 1, 2011:

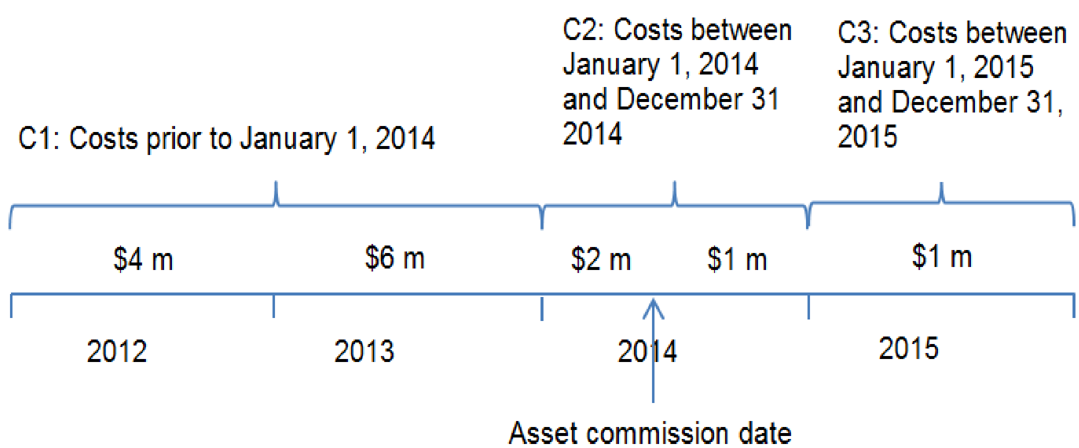
- The CCC on January 1 of the year in which an asset is commissioned is the sum of the construction or acquisition costs incurred prior to that day less the construction or acquisition costs of those parts of the asset placed into retirement prior to that day.
- Any construction/acquisition costs to complete the asset incurred on or after January 1 of the year of commissioning are added to the CCC on January 1 of the year following the date that cost was incurred.
- If a capital addition is made to an original capital asset and it is commissioned on or after January 1 of the year of commissioning the original capital asset, construction or acquisition costs of the capital addition incurred prior to December 31 of the year of commissioning the capital addition, greater than 10%

of the CCC, are added to the CCC on January 1 of the next year.

- Any construction/acquisition costs to complete the capital addition incurred after the year of commissioning the capital addition, greater than 10% of the CCC, are added to CCC on January 1 of the next year.
- If a part of a capital asset or a capital addition is placed into retirement during a calendar year, any construction and acquisition costs of the retired part are deducted from the CCC on January 1 of the next year.
- Capital additions of less than 10% of CCC are treated as operating costs.

Example 1:

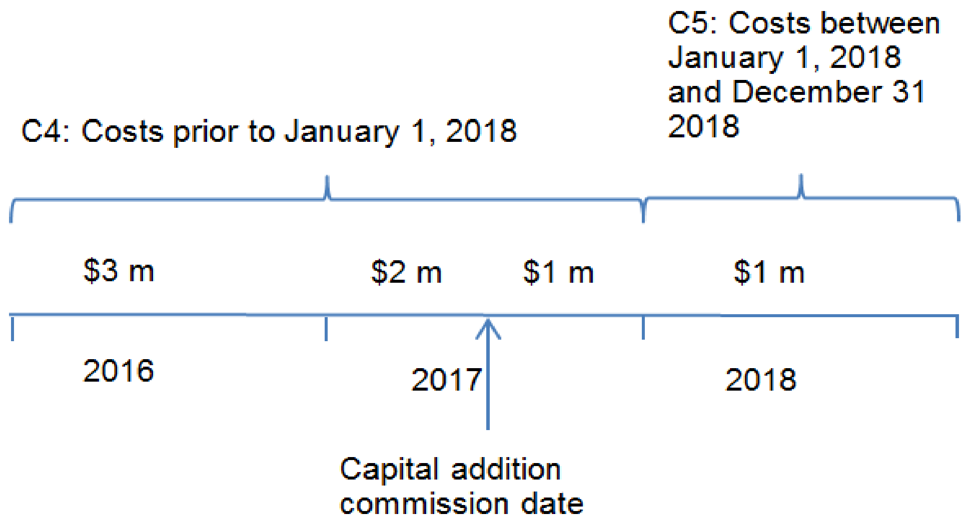
An asset was commissioned in May 1, 2014. The construction of the asset started in January 2012 with $4 million costs incurred in 2012, $6 million in 2013, $2 million from January 1, 2014 to April 30, 2014, and some completion costs incurred after the commission date comprising of $1 million from May 1 to December 31, 2014, and $1 million in 2015.



To calculate CCC, in the figure above, C1 gives rise to the first CCC of $10 million on January 1, 2014 ($4 million in 2012 +$6 million in 2013). C2 of $3 million is the summation of $2 million from January to April in 2014 and $1 million from May to December in 2014. On January 1, 2014, C2 of $3 million is added to the then current CCC of $10 million to derive the CCC of $13 million on January 1, 2015. On January 1, 2016, C3 of $1 million incurred in 2015 is added to the then current CCC of $13 million to derive the CCC of $14 million on January 1, 2016.

Example 2:

We continue Example 1 when the CCC on January 1, 2016 is $14 million. Now, a capital addition is commissioned on June 1, 2017. It started construction in January 2016 with $3 million costs incurred in 2016, $2 million between January 1 to May 31, 2017 and some completion costs incurred after the commission date of the capital addition comprising of $1 million from June 1 to December 31, 2017, and $1 million in 2018.



To calculate CCC, in the figure above, C4 of $6 ($3 + $2 + $1 million) is greater than 10 % of the CCC of $14 million on January 1, 2017 (Note: nothing happened during 2016 which would change the CCC, so the CCC on January 1, 2017 is equal to the CCC on January 1, 2016). Therefore, C4 of $6 million is added to the CCC of $14 million on January 1, 2017 to derive a CCC of $20 million on January 1, 2018. C5 of $1 million delayed costs incurred in 2018 is less than 10% of the CCC of $20 million on January 1, 2018. Therefore, it is considered as an operating cost in 2018 and should not be added to the CCC.

Depreciation Charge

A straight-line depreciation rate is applied to the CCC to calculate the depreciation charge for a calendar year.

- If an asset was commissioned on or after January 1, 2011, the depreciation charge for the commission year is 4% multiplied by the CCC on January 1 of the commission year multiplied by the number of days remaining in the calendar year after the commission date divided by 365. For example, an asset is commissioned on December 1, 2016. The depreciation in 2016 = 4% x CCC on January 1, 2016 x (31 days/365 days)
- For the subsequent calendar years, the deprecation charge is 4% of the CCC for that calendar year, provided that the depreciation charge cannot be greater than the IC for that calendar year. Otherwise, the depreciation charge will be the Initial Capital for the calendar year to ensure that the asset is fully depreciated in the last year of depreciation.
- If an asset was in service prior to January 1, 2011 and had been depreciated on a basis other than 4% straight line depreciation, the asset can be depreciated on that basis until such time as a capital addition greater than 10% of CCC is made

to the asset.

- The cost of land is not included to the depreciation determination.

Initial Capital and End Capital

For an asset commissioned on or after January 1, 2011, the Initial Capital and End Capital of an asset are annual calculations to reflect undepreciated capital costs at the beginning and the end of a year.

- The Initial Capital of a capital asset is determined as follows.
  - The Initial Capital at the beginning of the year in which an asset is commissioned is equal to the CCC on January 1 that year.
  - The Initial Capital on January 1 of subsequent calendar years is equal to the End Capital of the preceding year plus any completion costs of the asset and the construction, acquisition or completion costs of any capital additions (greater than 10% of CCC) during the preceding calendar year, minus the net book value of any retirements during the preceding calendar year.
- The End Capital for a calendar year is the Initial Capital of the calendar year minus the depreciation charge for the calendar year. It has a minimum value of zero.

For an asset commissioned prior to January 1, 2011, the Initial Capital of an asset on January 1, 2011, is a net book value of the capital asset on December 31, 2010.

Return on Capital

Return on capital is equal to the rate of return on capital multiplied by the average of the initial capital and the end capital of the asset, then multiplied by the ratio of number of days to 365. The "number of days" is discussed, below.

- The rate of return on capital is the long-term bond rate for the calendar year, unless the Minister has specifically authorized another rate. (See section 5.3.1.2 for cost of service calculation of pipeline services.)
- The "number of days" in the ratio is:
  - 365 if the asset is in service for the entire year.
  - The number of days from the commission date to the end of year in the commission year.
  - The number of days from the start of year to the retirement date in the asset retirement year.
  - The number of days from the commission date to the retirement date if the year is both the commission and retirement year.

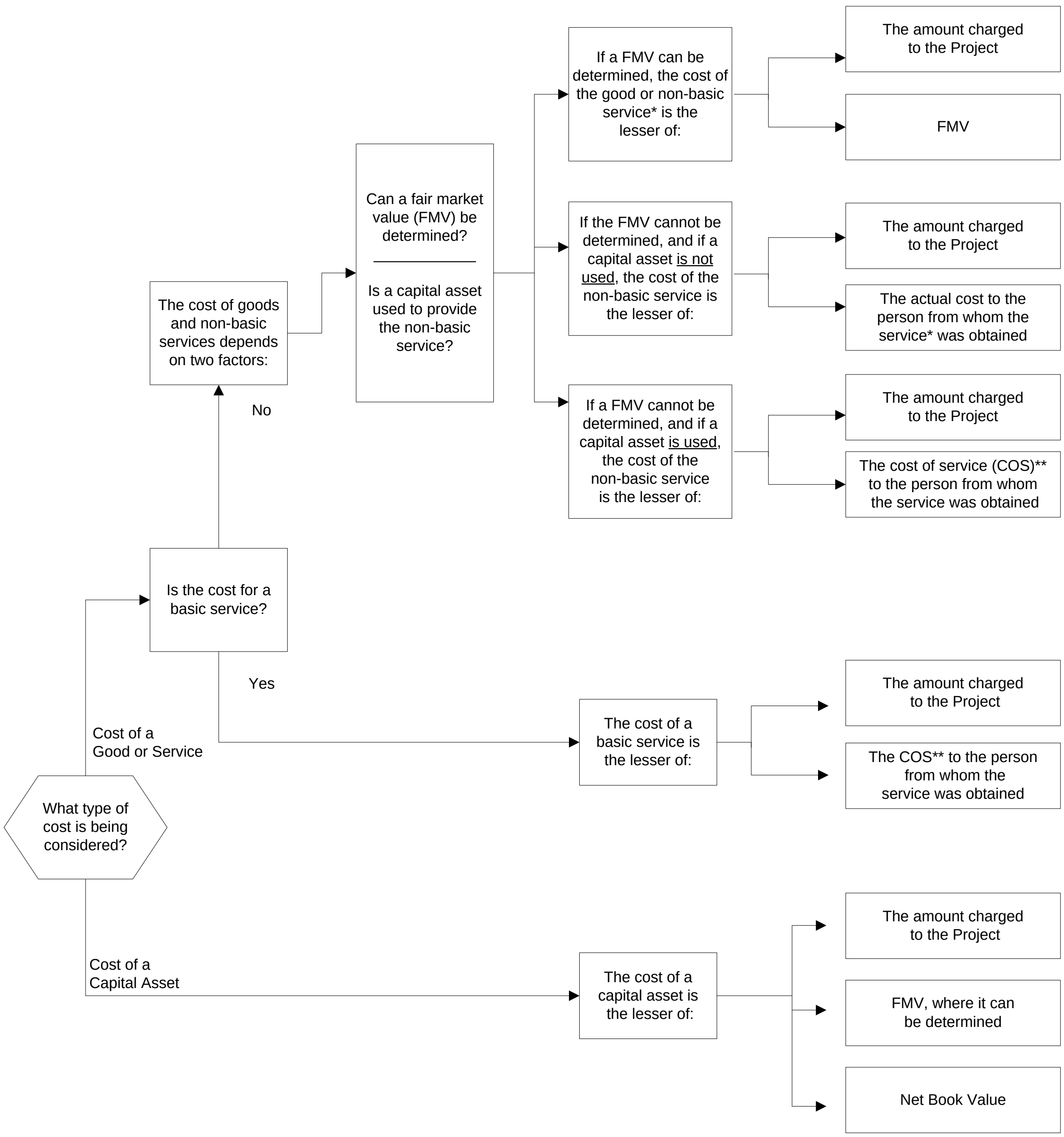
Example 3:

An asset is commissioned on July 1, 2016. The CCC and the Initial Capital in 2016 is \$100 million. No capital additions or retirements occurred in 2016. Depreciation during 2016 is equal to 4%x \$100 million x 184 days/365 days about \$2 million. The

End Capital in 2016 is $100 million - $2 million = $98 million. . Return on capital in 2016 = the rate of return on capital in 2016 x ($100 million + $98 million)/2 x 184 days/365 days.

6.3 Cost Rules for Non-Arm's Length diagram

Cost rules (simplified) for non-arms-length good, service, or asset acquisitions:



* See Oil Sands Allowed Cost (Ministerial) Regulation (OSAC) section 12(3) if the good is produced by a service using a capital asset.

** See OSAC section 12(4). In some circumstances the Minister may prescribe a charge in place of a COS.

6.4 Heat Transfer

In some integrated projects, synergistic benefits may accrue from the exchange of process heat between the OSR Project and non-Project components of the integrated project.

Where non-Project operations provide useful heat to the OSR Project, the value of that heat constitutes an allowed cost to the Project. Conversely, where the OSR Project provides useful heat to non-Project operations, the value of that heat is ONP to the OSR Project.

Details on the calculation and the valuation of heat transfer, and examples of that calculation can be found in the "Heat Transfer" paper in Appendix J.

7. Administration and Enforcement

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 35 to 49

A Project is defined to have reached payout on the first day of the month during which, for the first time, its cumulative revenue is equal to its cumulative cost. Payments are made on a monthly basis.

- For **Pre-Payout Projects**, the applicable Crown royalty share and royalty compensation are calculated and paid monthly.

  The calculation of the royalty compensation is based on the pre-payout gross royalty rate for the month, which varies from 1% to 9%, based on the West Texas Intermediate (WTI) price for the month, or

- **For Post-Payout Projects**, the applicable Crown royalty share and compensation in respect of royalty for a Period, are based on the greater of:
  - the post-payout gross royalty rate, which varies from 1% to 9% based on an average WTI price for the Period, or
  - the post-payout net royalty rate, which is calculated as: NRPF x NR/GR, where NRPF is the Post-Payout Net Royalty % Factor, which varies from 25% to 40% based on the average WTI price for the Period.

- Pre Payout royalty is calculated monthly based on the production month's information whereas Post Payout royalty is calculated based on the Period's information and a monthly instalment is then calculated based on the estimated annual royalty payable. Each month, estimated post-payout gross royalty rates and post-payout net royalty percentage factor are published on the Alberta Energy website (http://www.energy.alberta.ca/Pages/default.aspx) for use in the calculation of these instalments.

  The monthly royalty rates are published in the Department's monthly Information Letter (Oil Sands Monthly Royalty Rates and BVM Pricing Components). From the Department's website (http://www.energy.alberta.ca/), navigate to "Related Links", then "Information Letters". In addition, the monthly royalty rates may be found by navigating to "Oil Sands", "Oil Sands Royalties", and "Monthly Royalty Rates".

What is a Period?

Section 1(y) of the OSRR09 defines a Period as each **calendar year** or partial calendar year that occurs between the Project's effective date and the date when Project approval is revoked.

When a Project reaches payout part way through a year this divides the year into two Periods for reporting purposes. The last day of the pre-payout Period is the last day of the month before the post-payout Period begins. The post-payout Period begins on the first day of the month in which payout occurs.

As per Section 25(1), a Project reaches payout on:

1. Its effective date (which is always the first day of a month) if it has a zero or negative PNCB. If such a Project's effective date was, for example, July 1st, that year would be divided into a pre-payout Period ending June 30th, and a post-payout Period beginning July 1st.

2. The first day of the month in which its cumulative revenue first equals its cumulative cost, for a Project which has a positive PNCB. If such a Project's cumulative cost was greater than its cumulative revenue on July 1st, but less than or equal to its cumulative revenue on July 31st, the Project's payout date would be July 1st, and the year would be divided into a pre-payout and a post-payout Period as in (1) above.

7.1 Oil Sands General Form Information

Oil Sands Royalty reporting forms are available for download on the Department's website in Excel or PDF format (From the Department's website (http://www.energy.alberta.ca/), navigate to "Oil Sands," then "Forms."), however all submissions must be made through the secure web application Electronic Transfer System (ETS) in Excel format. Non Project Royalty (NPR) submissions can also be submitted in XML format.

Please note these Excel spreadsheets will be downloaded into a database – and therefore no revisions to the forms' formats will be allowed.

If you have any concerns with form access and require assistance, contact the "Oil Sands Royalty Account Inquiries" team. (See Appendix G, "Contact Information" or via the OS Reporting Mailbox - OSReport@gov.ab.ca).

OSR Reporting Requirements:

1) For new OSR Project Approvals or OSR Project Expansions, operators must file the monthly and annual royalty reporting and CARE reporting in compliance with the filing deadlines. Penalties may be levied if the forms are missing or

submitted late (OSRR09 Section 44).

2) For CARE reporting, if the approval date occurs in the next reporting Period, CARE reporting would be required for both the Period when the OSR Project became effective and the current reporting Period.

7.2 Reporting Changes

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 41

When an operator or other person who has furnished a report under Part 5 “Administration and Enforcement” of OSRR09, learns of a material change or error in, or a material omission from, the information contained in that report, an amended report containing the updated, corrected or missing information must be submitted to the Department.

- The operator or other person who has furnished a report must submit the amended report by the last day of the month following the month in which, the material change, error or omission is identified.

If an operator or other person has received notice from the Department to furnish an amended report, the operator must submit an amended report accompanied by a Statement of Approval and/or Opinion from Auditors to the Department. The report must be submitted by the last day of the month following the month in which:

- The Department issues the notice requesting an amendment to the report filed.

7.3 Reporting Requirements - Non-Project Royalty Calculation

7.3.1 Non-Project Mining Operations

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 26

The Crown share of oil sands recovered from a non-Project oil sands mining operation is equal to 20% of the oil sands delivered in each month at the boundary of the oil sands lease.

The royalty payable to the Crown in respect of this share is the quantity of the Crown share multiplied by the Oil Sands Par Price prescribed for that month. This Oil Sands Par Price is prescribed monthly by the Department and published in an Information Letter. From the Department’s website (http://www.energy.alberta.ca/), navigate to “Related Links”, then to “Information Letters”.

7.3.2 Non-Project Well Events

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 27 and 28

For wells spudded prior to January 1, 2017, each month, the Crown's share of the oil sands product recovered from a non-Project well event is the share that would be reserved to the Crown under the *Petroleum Royalty Regulation, 2009* if the oil sands product was crude oil. Wells spudded on or after January 1, 2017 will be regulated under the *Petroleum Royalty Regulation, 2017(*PRR2017).

The PRR2017 partially emulates a revenue minus cost royalty structure. The Drilling and Completion Cost Allowance (C*), based on average industry drilling and completion costs, is a proxy for well costs. It determines the allowable revenue after which individual wells begin paying higher royalty rates (post-payout).

The Crown's royalty share for each oil sands product is automatically transferred to the lessee at the point immediately downstream from the well.

The royalty payable to the Crown in each month is calculated as the volume of the Crown's share multiplied by the unit value, as determined by the Minister, for each kind of oil sands product. It must be paid to the Crown no later than the last day of the following month.

7.3.2.1 Determining Crown Royalty Share

The Crown royalty share of marketable crude oil from a non-Project well-event is a portion of the crude oil obtained in a month from the well-event. It is calculated as follows:

To calculate royalties under the Albert Royalty Framework Formulas (ARF), multiply

The quantity of marketable crude oil obtained at the wellhead of the well-event from which the crude oil is produced and recovered

X

The Crown royalty formula for the marketable crude oil

X

The Crown interest percentage for the subject well-event

X

The Unit Value where the unit value is calculated as:

1) If greater than or equal to 40% of the Crown's royalty share of crude bitumen dispositions are from arms-length transactions, then the proceeds of these dispositions may be used to calculate the unit value, or
2) If less than 40% of the Crown's royalty share of crude bitumen dispositions is from arms-length transactions, then a BVM will be determined for the non-arm's length transaction.

Less costs or allowances for trucking the Crown's royalty share of crude bitumen from the well to a pipeline terminal.

For Modernized Royalty Framework projects the company will pay a flat royalty of five per cent on early production up until well revenue equals the Drilling and Completion Cost allowance, a standardized value that takes into account the well's true vertical depth, total lateral depth and amount of drilling or fracturing material used.

Afterwards, the company will pay royalty rates ranging from 5% to 40% (dependent on price) on all subsequent production.

In determining the unit value, the Minister will consider revenues from the disposition of the oil sands product during that month. The unit value cannot be less than zero.

The Minister may reduce the royalty payable in a month by costs or allowances for trucking the Crown's royalty share of crude bitumen from the well to the pipeline terminal in the following circumstances:

- Where trucking costs are incurred from the last facility at which impurities are removed from the crude bitumen before the crude bitumen is delivered into a pipeline, and
- Where trucking costs are incurred to an unloading facility connected to a pipeline.

The costs and allowances may not exceed the royalty payable in the month.

NPR wells that have applied for MRF strategic program benefits will not be allowed to form part of an oil sands royalty Project.

NPR wells that have received an MRF drilling and completion cost allowance may be allowed to form part of an oil sands royalty Project provided:

- an oil sands royalty Project application has been submitted within 12 months beginning on the first day of the month in which the royalty share for that non-

Project well is determined under the MRF;

- an oil sands royalty Project approval or amendment approval is granted; and
- royalty payable in respect of the time prior to the NPR well forming part of the Project has been recalculated as though the well's total revenue were equal to C*.

Non Project Well Royalty Reporting (NPR) forms are available for download on the Department's website in Excel and PDF format.

From the Department's website (http://www.energy.alberta.ca/), navigate to "Oil Sands," then "Forms.").

Submission of the NPR form must be made through the secure web application Electronic Transfer System (ETS) submitted in Excel Format. See section 7.9 – "Royalty Reporting Formats and Timing" and Appendix H for ETS – "File Naming Conventions".

7.3.2.2 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 27(1) and section 38(2)

Unless the Minister states otherwise, the NPR form for reporting non-Project royalty must be submitted by the last day of the month, following the production month. (The NPR form is required to be submitted regardless of whether the well event has produced.) Royalty must be paid to the Crown no later than the last day of the month, following the production month in respect of the Crown's royalty share.

Any oil sands royalty Project wells that are no longer in a Project due to Project revocation or termination will pay royalty as follows:

- If its first well event was spud before January 1, 2017, pursuant to the *Petroleum Royalty Regulation, 2009* until December 26, 2026, and thereafter pursuant to the *Petroleum Royalty Regulation, 2017* as though the well's total revenue was equal to C*, as C* is determined under the *Petroleum Royalty Regulation, 2017* .
- If its first well event was spud on or after January 1, 2017, pursuant to the *Petroleum Royalty Regulation, 2017* as though the well's total revenue was equal to C*, as C* is determined under the *Petroleum Royalty Regulation, 2017*.

Interest is levied on unpaid royalties or underpayments of royalties payable (See section 7.12, "Interest" – reference section 45(1)(a) of OSRR09)

A penalty may be levied if the Non-Project Royalty Submission form is missing or submitted late. (See section 7.11, "Penalties.)

The Minister may require the licensee or the operator of a NPR well to provide information required under the *Petroleum Royalty Regulation, 2017*, the *Enhanced Hydrocarbon Recovery Royalty Regulation* or the *Emerging Resources Royalty Regulation*. The failure of providing such information timely may encounter a penalty. If the reporting due date falls on a non-business day, the next business day will apply as the due date. However, for a payment due by the last day of March, the payment is due on the last day in March on which the offices of the Department are open.

7.4 Reporting Requirements for Pre-Payout Project

7.4.1 Monthly Royalty Calculation Reporting Forms

Oil Sands Royalty Regulation, 2009 (AR 223/2008) Section 38

The Crown's royalty share for each oil sands product that was recovered from the development area and delivered to the RCP for that product must be reported to the Department each month.

The monthly royalty calculation is submitted to the Department on a monthly royalty calculation (MRC) reporting form. The MRC provides financial information for each month during the Period. This includes actual volumetric and revenue data for the current and past months and estimated volumetric and revenue data for future months. Although royalty is calculated for each reported month in the Period, royalty is only payable on the current production month and any royalty adjustments on past production months.

MRC reporting forms are available for download on the Department's website in Excel and pdf format (http://www.energy.alberta.ca/); navigate to "Oil Sands," then "Forms."), however all submissions of the MRC must be made through the secure web application Electronic Transfer System (ETS) in Excel format. See section 7.9 – "Royalty Reporting Formats and Timing"

Note:

> If the Minister is not satisfied with the accuracy of the estimated data, the Minister has the ability to substitute an estimate for the data contained in a MRC, and will provide notice to the operator of the amount that has been substituted.

The following are entry fields on the MRC where the operator must report data. All other fields on this form are calculated. Calculation formulas are identified in the Calculation sheet of the MRC form.

The actual and estimated Production, AL (Arm's Length) Sales & Handling Charges for the reporting month

- Total Crude Bitumen Production (m3)
- Crude Bitumen Volume at RCP (Royalty Calculation Point) (m3)
- Blended Bitumen <Blend Type(s)> Volume at RCP (m3)
- Other Oil Sands Products Volume at RCP (unit)
- Crude Bitumen AL Sales Volume (m3)
- Blended Bitumen <Blend Type(s)> AL Sales Volume (m3)
- Other Oil Sands Products AL Sales Volume (unit)
- Crude Bitumen AL Sales Value ($)
- Blended Bitumen <Blend Type(s)> AL Sales Value ($)

- Other Oil Sands Products AL Sales Value ($)
- Crude Bitumen Handling Charges for AL Sales ($)
- Blended Bitumen<Blend Type(s)>Handling Charges for AL Sales ($)
- Other Oil Sands Products Handling Charges for AL Sales ($)
- Crude Bitumen NAL Sales Volume (m3)
- Blended Bitumen <Blend Type(s)> NAL Sales Volume (m3)
- Other Oil Sands Products NAL Sales Volume (unit)
- Crude Bitumen NAL Sales Value ($)
- Blended Bitumen <Blend Type(s)> NAL Sales Value ($)
- Other Oil Sands Products NAL Sales Value ($)
- Crude Bitumen Handling Charges for NAL Sales ($)
- Blended Bitumen<Blend Type(s)>Handling Charges for NAL Sales ($)
- Other Oil Sands Products Handling Charges for NAL Sales ($)
- Diluent in NAL Sales Volume (m3)
- Diluent Value in NAL Sales ($)
- Bitumen Hardisty BVM Price ($/m3)
- Other Oil Sands Product Fair Market Value (FMV) ($/unit)
- Bitumen Density (kg/m3)
- BVM Transportation Allowance ($/m3)
- Project Revenue (Total) – Calculated field
- Diluent in AL Sales Volume (m3)
- Diluent in Volume at RCP (m3)
- Diluent Value in AL Sales ($)
- Diluent Value in Volume at RCP ($)

The appropriate portion of diluent cost is deducted from the value of the Crown's royalty share.

- Project Operations (excludes cost of diluent)
- Capital
- Project Expansion PNCB
- Other Net Proceeds Earned
- Royalty Rate (Use the current month royalty rate to estimate the royalty for the remaining months of the year.)
- Previous Royalty Calculated for the month (Only required for the month if you are amending the MRC form)

The Project operator who completes the MRC must include contact information for the operator's representative who completed the form including name, e-mail address, telephone number, and date the MRC was prepared. (See section 7.8.4.1 "Required Information")

7.4.1.1 Amendments

When past production months' information needs to be amended, the operator must make the amendment of that production month in the current MRC report month's submission. The operator must indicate the previous royalty that was calculated for the amended production month in order to calculate the appropriate royalty adjustments on the amended information. Amendments may result in an over- or under-payment of past royalties. The royalty adjustments from amendments may be subject to interest.

If the amendment results in an underpayment of royalty, this underpayment will be assessed interest. Compound interest would be calculated starting the first day after the royalty was payable. (See Appendix I, "Oil Sands Royalty Reporting Interest Rules). For example, royalty for oil sands products sold or disposed of in April is due on May 31 even if an amended report is submitted after this date. Interest on an underpayment would be calculated as of June 1.

The Crown does not pay interest on royalty overpayments made by the operator, whether the overpayment was made on the current or past production month(s).

Note

> MRC amendments to production months in the period after the end of the period can be reported directly in Schedule 6 of the Pre Payout End of Period Statement royalty template.

7.4.1.2 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), Section 29(1) and Section 38

Pre-payout MRCs must be submitted by the last day of the month following the production month, along with the payment of the royalty calculated on the MRCs or on the date specified by the Minister. (Reference Section 33(1) of OSRR'09))

Interest is levied on unpaid royalties or underpayments of royalties payable (See section) (OSRR'09 - Section 45)7.12, "Interest".)

A late filing penalty may be levied if the MRC form is missing or submitted late. (See section 7.11 "Penalties).

For example, production and royalty for April is required to be reported by May 31. Penalties and interest may be levied if the pre-payout MRCs are submitted late, or incomplete.

If the MRC due date falls on a non-business day, the due date will be the next business day. For a MRC royalty payment due by the last day of March, the payment is due on the last day in March on which the offices of the Department are open.

OSR Project Suspended but not Revoked:

> Filings of the MRCs are required until the OSR Project is revoked. Operators may write to the Director, Royalty and Tenure Operations, for consideration of a filing exemption if their Project is to be suspended for a long period. Operators must continue to submit all required reports, even if production has been suspended.

7.4.2 Pre-Payout End of Period Statement

Oil Sands Royalty Regulation, 2009 (AR 223/2008) Section 39

End of Period Statements (EOPS) detail Project operations on both a financial and a production perspective.

The Project operator who completes the EOPS must include contact information such as name, e-mail address, telephone number and date prepared. (See section 7.9.4.1 “Required Information”).

EOPS are available for download on the Department’s website in Excel format (from the Department’s website (http://www.energy.alberta.ca), navigate to “Oil Sands,” then “Forms.”). However, submission of the EOPs must be made through ETS. See section 7.9 – “Royalty Reporting Formats and Timing”.

7.4.2.1 Contents of Pre-Payout End of Period Statement (EOPs)

7.4.2.1.1 Statement Requirement (PRE-1)

This reporting schedule indicates the regulatory reporting requirements for the EOPs.

1. EOPS must be submitted to the Department’s Oil Sands Operations Branch within three months after the end of each Period.
2. If the aggregated quantity of bitumen measured at the RCP during the Period is greater than an average of 1,590 m^3 per day, the EOPs must be accompanied by an independent auditor's opinion.
   - If an independent auditor’s opinion is required, the auditing firm must provide a signed letter verifying that, in the firm’s opinion, the Project operator has complied with the requirements of the OSRR09.
   - If the Project reached the 1,590 m^3 per day threshold, the independent auditor’s opinion applies only to the current period cost and revenue portion of the statements, and not to the opening cumulative balance. However, since both the opening balance and the current Period amounts affect the Project’s return allowances, the auditor must acknowledge that the opening amounts were not examined.
   - If Project production at RCP is less than the 1,590 m^3 per day threshold, statements prepared by Project operators are sufficient.

All EOPS—whether they were independently audited or not—are subject to audits conducted by the Department. (See section 7.14, “Audits”)

3. The EOPS statement must be signed by the operator or operator's representative and must be accompanied by a statement indicating approval of the report by the Chief Financial Officer, or by a senior officer of the operator approved in advance by the Department. This can be provided on a separate document. The document must indicate the Project(s) and Royalty Payable(s) that are signed by the operator (operator's representative) and approved by the operator's Chief Financial Officer or Department approved senior officer. (Refer to Information Bulletin (IB) 2009-03)

7.4.2.1.2 **Reason for Amendment (PRE-1a)**

This reporting schedule is required only if the operator is amending the report. The operator is required to state the reason(s) for the EOPS amendment.

7.4.2.1.3 **Project Payout Status (PRE-2)**

This reporting schedule identifies the cumulative costs, revenue and net cumulative balance of the Project at the end of the Period. An expected payout date for the Project is also required.

7.4.2.1.4 **Allowed Costs Summary and Detail (PRE-3 and PRE-3a)**

All costs reported are in accordance with the OSACR.

These reporting schedules report the Period and monthly amounts for allowed costs incurred in the following categories:

- operating costs
- capital costs
- Project expansion PNCB
- diluent costs
- royalty payable
- return allowance earned

Costs reported for the month must comply with Section 18(1) of the OSRR'09. Costs are paid within 90 days of the cost becoming payable.

7.4.2.1.5 **Return Allowance (PRE-4)**

This reporting schedule determines the monthly Return Allowance Calculated and Return Allowance Earned information. The Return Allowance Earned is the Return Allowance Calculated from the previous month. The Return Allowance Earned is an allowed cost. See section 4.2.2 “The Return Allowance”

7.4.2.1.6 **Revenue Summary (PRE-5)**

This reporting schedule summarizes the total Project revenue generated for each month of the Period. Project revenue less the cost of diluent determines the Project’s Gross Revenue. Monthly Other Net Proceeds (ONPs) are added to the Project Revenue to determine the Project’s cumulative revenue for each month.

Revenues from ONP are further categorized at the Period level as proceeds from:

- Disposition of assets and non-oil sands' products
- Sale / lease of technology
- Insurance and legal settlements
- Custom processing and transportation fees
- Processing of project owners' non-project substances

7.4.2.1.7 **Revenue and Royalty Details (PRE-6)**

This reporting schedule identifies the monthly revenue and royalty information at the end of the Period. This schedule is equivalent to the MRC form and replaces the need to submit the MRC form after the last report month in the Period.

7.4.2.2 Amendments

Project operators can file amendments to the EOPS within four years of the end of the Period. If the Department audit amends an operator's cost or revenue calculation approach methodology, or any other facet of the royalty calculation, the operator must use the audit approach methodology in all future reporting periods and amend all reporting to reflect this change.

7.4.2.3 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), Section 39

Pre-payout EOPS must be submitted within three months of the end of each Period. For example, if the Period ends on December 31, the EOPS must be submitted by March 31 of the following year unless otherwise specified by the Minister. If the due date falls on a non-business day, the next business day will apply as a due date.

Interest is levied on unpaid royalties or underpayments of royalties payable. (OSRR'09 - Section 45)7.12, "Interest".)

A late filing penalty may be levied if the EOPS is missing or submitted late. (OSRR'09 – Section 44)7.11 "Penalties".)

OSR Project Suspended but not Revoked:

> Filings of the Pre-Payout EOPS are required until the OSR Project is revoked. Operators must continue to submit all required reports, even if production has been suspended.

7.5 Reporting Requirements for Post-Payout Projects

Royalty calculations are submitted to the Department on a Good Faith Estimate (GFE) form. Each month operators are required to submit actual volumetric and revenue information for past months and estimated information for future months.

GFE reporting forms are available for download from the Department's website in Excel and PDF format (From the Department's website (http://www.energy.alberta.ca/). Navigate to "Oil Sands," then "Forms."), however all submissions of the GFE must be made through the secure web application Electronic Transfer System (ETS) in Excel format. See section 7.9 – "Royalty Reporting Formats and Timing".

7.5.1 Monthly Good Faith Estimates Reporting Forms

For post-payout Projects, Good Faith Estimates (GFE) are submitted each month. Like the monthly MRC reports submitted for pre-payout Projects, GFEs provide Project identification, contact and royalty calculation information.

The GFE provides financial information for each month during the Period. This includes actual volumetric and revenue data for the current and past months and estimated volumetric and revenue data for future months. A monthly royalty installment is calculated based on the estimated royalty for the Period and the cumulative installments paid to date.

Note 1:

> Monthly installments for post payout Projects are never adjusted after the installment has been charged. Instead, the remaining installments will be adjusted to account for any difference in arriving at the annual royalty payable.

The Project operator who completes the GFE must include contact information such as; name, e-mail address, telephone number and the date on which the GFE was prepared.

Note 2:

> If a past production month's information needs to be amended, it must be made in that production month of the current GFE report month's submission. For example, production month 2013-05 information needs to be amended. Current report month is 2013-06. The amendment would be reported in the 2013-05 production month of the 2013-06 report month's GFE.

Note 3:

> Reasonable estimates must be provided as the estimates directly affect the estimated annual royalty which is used to calculate the monthly royalty installment payable.

> If the Minister is not satisfied with the reasonableness of the estimate, the Minister has the ability to substitute any estimate of the amount contained in a monthly report (GFE), and will provide notice to the operator of the amount that has been substituted. (OSRR '09, Section 38(7) and (8))

The following are data entry fields on the GFE form where the operator must report data. All other fields on this form are calculated fields. Calculation formulas are identified in the calculation sheet of the GFE form.

Indicating either Actual or Estimate, the reporting requirements for the Production, AL (Arm's Length) Sales & Handling Charges for the reporting month are:

- Total Crude Bitumen Production (m^3)
- Crude Bitumen Volume at RCP (m^3)
- Blended Bitumen <Blend Type(s)> Volume at RCP (m^3)
- Other Oil Sands Products Volume at RCP (unit)
- Crude Bitumen AL Sales Volume (m^3)
- Blended Bitumen <Blend Type(s)> AL Sales Volume (m^3)
- Other Oil Sands Products AL Sales Volume (unit)
- Crude Bitumen AL Sales Value ($)
- Blended Bitumen <Blend Type(s)> AL Sales Value ($)
- Other Oil Sands Products AL Sales Value ($)
- Crude Bitumen Handling Charges for AL Sales ($)
- Blended Bitumen <Blend Type(s)> Handling Charges for AL Sales ($)
- Other Oil Sands Products Handling Charges for AL Sales ($)
- Crude Bitumen NAL Sales Volume (m^3)
- Blended Bitumen <Blend Type(s)> NAL Sales Volume (m^3)
- Other Oil Sands Products NAL Sales Volume (unit)
- Crude Bitumen NAL Sales Value ($)
- Blended Bitumen <Blend Type(s)> NAL Sales Value ($)
- Other Oil Sands Products NAL Sales Value ($)
- Crude Bitumen Handling Charges for NAL Sales ($)
- Blended Bitumen<Blend Type(s)>Handling Charges for NAL Sales ($)
- Other Oil Sands Products Handling Charges for NAL Sales ($)
- Diluent in NAL Sales Volume (m^3)
- Diluent Value in NAL Sales ($)
  - Bitumen Adjusted BVM Price ($/$m^3$)
  - Other Oil Sands Product Fair Market Value (FMV) ($/unit)

    - Bitumen Density (kg/m^3)
    - BVM transportation allowance (\$/m^3)
    - Project Revenue (used to calculate Net Revenue) – Calculated field
        - The Project revenue is the sum of Product Revenues (e.g. Crude Bitumen Revenue + Blended Bitumen Revenue + Other Oil Sands Product Bitumen Revenue) of all leased oil sands products less their respective handling charges. This amount is used to calculate the net revenue. The Project revenue less the cost of diluent determines the gross revenue.
- Diluent in AL Sales Volume (m^3)
- Diluent in Volume at RCP (m^3)
- Diluent Value in AL Sales (\$)
- Diluent Value in Volume at RCP (\$)
- Project Operations (excludes cost of diluent)
- Capital
- Project Expansion PNCB
- Cumulative Balance Carried Forward Upon Payout
- Previous Period's Net Loss
- Return Allowance on Previous Period's Net Loss
- Excess of Previous Period's GRR over NRR
- Excess of Previous Period's ONP over Total Allowed Costs (AC)
- Other Net Proceeds Earned (in the Period)
    - Allowed costs can be reduced by the total amount of Other Net Proceeds (ONP) earned by the Project, but the reduction claimed cannot exceed the original amount of the allowed costs.
    - If Other Net Proceeds exceed allowed costs, the allowed costs are reduced to zero and the unused portion of the Other Net Proceeds is carried forward to the next Period as a deduction to the allowed cost. The excess is carried forward until it is depleted.
- Net Revenue Royalty Rate
- Gross Revenue Royalty Rate
    - Use the estimated post-payout gross and post-payout net royalty rates from the current month's Information Letter (Oil Sands Monthly Royalty Rates and BVM Pricing Components) to estimate the royalty for the remaining months of the year.
    - For the current production month and future months, input the current Royalty Calculated amount as the Monthly Royalty Installment. For production months previous to the current production month, input the original Royalty Calculated amount (i.e. monthly installment calculated previously) as the Monthly Royalty Installment.

- If a Project has a net loss in a Period, it is carried forward to the next Period as an allowed cost.
- Effective for the 2009 Period the monthly royalty rates are published in the Department's monthly Information Letter (Oil Sands Monthly Royalty Rates and BVM Pricing Components). From the Department's website (http://www.energy.alberta.ca/Pages/default.aspx), navigate to "Oil Sands", "Related Links", and " Information Letters ".

7.5.1.1 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), Sections 33 and 38

Good Faith Estimates (GFEs) and the associated royalty installments must be submitted by the last day of the month following the production month unless otherwise specified by the Minister. For example, production and royalty payable for April would be reported by May 31. (OSRR'09 - Section 33(9)).

Interest is levied on unpaid royalties or underpayments of royalties payable. (See section 7.12, "Interest") (OSRR'09 - Section 45).

A late filing penalty may be levied if the GFE form is missing or submitted late. (See section 7.11 "Penalties") If the due date falls on a non-business day, the next business day will apply as a due date. (OSRR'09 – Section 44)

Exceptions

Newly approved or amended Projects normally have retroactive effective dates. For example, a Project approved in March (current report month) might have an effective date of January. In this case, the reporting information for January, February and March production months would be reported in the March GFE report month's submission, due by April 30th. Due dates for subsequent report months' reports would follow the regular schedule.

7.5.2 Post-Payout End of Period Statements

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 39

EOPS detail Project operations from both a financial and a production perspective.

The Project operator who completes the EOPS must include contact information for the operator's representative that has completed the form such as; name, e-mail address, telephone number and indicate the EOPS date prepared.

EOPS (post-payout) are available for download from the Department's website in Excel and PDF format (http://www.energy.alberta.ca/), Navigate to "Oil Sands," then "Forms"). All submissions of the EOPS must be made through the secure web application Electronic Transfer System (ETS) in Excel format. See section 7.9 – "Royalty Reporting Formats and Timing".

7.5.2.1 Contents of Post-Payout End of Period Statement (EOPs)

7.5.2.1.1 Statement Requirement (PST-1)

- Unless the Minister directs it, EOPS must be submitted to the Department's Oil Sands Operations Branch within 3 months after the end of each Period.
- If the aggregated quantity of bitumen measured at the Royalty Calculation Point (RCP) during the Period is greater than an average of 1,590 m^3 per day, the EOPS must be accompanied by an independent auditor's opinion.
- If an independent audit is required, the auditing firm must provide a signed letter verifying that, in the firm's opinion, the Project operator has complied with the requirements of the Regulation.
- If Project production at RCP are less than the 1,590 m^3 per day threshold, statements prepared by Project operators are sufficient.

All EOPS—whether they were independently audited or not—are subject to audits conducted by the Department. (See section 7.3 – "Audits")

- The EOPS must be signed by the operator or operator's representative and must be accompanied by a statement indicating approval of the report by the Chief Financial Officer, or another individual approved by the Minister. This can be provided on a separate document. The document must indicate the Project(s) and Royalty Payable(s) that are signed by the operator (operator's representative) and approved by the operator's Chief Financial Officer or Department approved individual. (Refer to Information Bulletin 2009-03).

7.5.2.1.2 Reason for Amendment (PST-1a)

This reporting schedule is required to be completed only if the operator is amending the report. The operator is required to state the reason(s) for the amendment.

7.5.2.1.3 Royalty Payable (PST-2)

This reporting schedule identifies the gross revenue royalty, net revenue royalty and the previous royalty or installments calculated for the Period to arrive at the royalty payable or refund amount at the end of the Period. Supporting calculations are identified in the Royalty Calculation (PST-3).

7.5.2.1.4 Royalty Calculation (PST-3)

This reporting schedule calculates the gross revenue royalty and net revenue royalty of the Project. The greater of these amounts is the annual royalty payable. If gross revenue royalty exceeds net revenue royalty, the excess is carried forward as an allowed cost for the next Period.

The components used in the royalty calculation (Project revenue, the cost of diluent, allowed costs and the allowable portion of Other Net Proceeds) are derived from forms PST-4, PST-5 and PST-7.

7.5.2.1.5 Allowed Cost Summary and Detail (PST-4 and PST-4a)

These reporting schedules report the Period and monthly amounts for allowed costs incurred in the following categories:

- Cumulative balance carried forward upon payout
- Operating costs
- Capital costs
- Project expansion PNCB
- Diluent costs
- Return allowance on the previous period's net loss
- Net loss carried forward from the previous period
- Excess gross revenue royalty paid in the previous period
- Return allowance on the previous period's net loss

Pursuant to OSRR 2009 Section 18(1) costs reported as incurred for the month must be paid within 90 days after the costs become payable to be eligible costs for the Period.

7.5.2.1.6 **Other Net Proceeds (ONP) (PST-5)**

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 23

This reporting schedule identifies the ONP of the Project at the Period level. Monthly ONP are reported in Revenue Detail PST-7a. In a post-payout Period, the amount of ONP that can be used to reduce allowed costs cannot exceed the total amount of allowed costs. Any excess of ONP over allowed costs is carried forward as a deduction against the allowed costs for the next Period.

7.5.2.1.7 **Return Allowance (PST-6)**

This reporting schedule calculates the return allowance for the Period. A return allowance is provided only when the Project has a net loss at the end of a Period.

7.5.2.1.8 **Revenue Summary (PST-7)**

This reporting schedule summarizes the monthly Project revenue, diluent, and gross revenue of the Project.

7.5.2.1.9 **Revenue Detail (PST-7a)**

This reporting schedule identifies the monthly supporting information for the revenue calculation, such as production, sales, diluent, unit values, and ONP.

7.5.2.1.10 **Carry Forward Amounts (PST-8)**

This reporting schedule identifies the cost and revenue items that can be carried forward to the next Period:

- the net loss during the Period,

- the return allowance for current Period's net loss,
- the excess of gross revenue royalty over net revenue royalty, and
- the excess of ONP over total allowed costs (carried forward to the next Period's other net proceeds).

7.5.2.2 Amendments

The Department will accept amendments to the EOPS for a post payout Project within 4 years of the end of the Period.

7.5.2.3 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 39

Post payout EOPS must be submitted within three months of the end of each Period. For example, if the period ends on December 31, the EOPS must be submitted by March 31 of the following year. If the due date falls on a non-business day, the next business day will apply as the due date.

Royalty payment associated with the EOPS is due no later than April 30 of the following year.

Late filing penalties may be levied if the EOPS is submitted late. (OSRR'09 – Section 44) Interest will be charged if royalty or penalties are not paid on time. (OSRR'09 - Section 45) (See section 7.11 "Penalties" and section 7.12, "Interest")

OSR Project Suspended but not Revoked:

1. Filings of the EOPSs are still required until the OSR Project is revoked.
2. Operators may write to the Director, Royalty and Tenure Operations, for consideration of a filing exemption if their Project is to be suspended for a long period.
3. Operators must continue to submit all required reports, even if production has been suspended.

7.6 The Operator's Forecast

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 37

Operators' Forecasts are required for both pre-payout and post-payout Projects and should include additional notes, as required; to interpret and clarify volumetric and revenue information submitted.

Operator's Forecasts are used to estimate oil sands royalty revenues expected by the Crown for the current calendar year plus the next 14 calendar years, and to inform the Crown as to when the Project payout date is expected to occur.

Operator's Forecast Reports are now submitted electronically through ETS. See Section 7.9 Royalty Reporting Format and Timing.

Note

> In some cases, the Department may request the operator to provide a presentation to support the submitted forecasts.

7.6.1 Operators Forecast Submission Procedures

Step 1: Complete the Operator's Forecast Report

The Operator's Forecast Report is available for download on from the Department's website in Excel format (From the Department's website (http://www.energy.alberta.ca/) navigate to "Oil Sands", and then "Forms").

Step 2: Save the form using the following naming format:

OSR Project Number_ Year_Report Name

Example: OSR015_2009_Operators_Forecast.xls

Step 3: Submitting the Report

The completed Operator's Forecast Report must be submitted through the secure web application Electronic Transfer System (ETS).

Electronic Transfer System (ETS)

To receive access to the Electronic Transfer System, an ETS account Set Up / Change Form must be submitted to the Department.

See Section 7.9– "Royalty Reporting Formats and Timing" for additional information.

Note

> In the ETS Account Set Up/Change form ensure to check the Oil Sands - Supplemental Reporting box as this will allow you to submit the Operator's Forecast Report.

7.6.2 Operator's Forecast Report

The Project operator must complete the Operators Forecast Report in accordance with the instructions given in the Report form.

Project identification - the Project operator who completes the Operator's Forecast Report must include:

Project Name

OSR Approval Number

Project Operator ID

Main contact information must include; name, position, e-mail address, telephone number and date prepared (as well as "alternate contact" information) and indicate the date the Operator's Forecast has been prepared.

Operators must provide projected estimates on the following:

1. Units

    - All monetary values such as prices, costs and revenues should be reported in current year Canadian dollars. (e.g. real dollars as of

2010)

- For all other units, follow the units shown on the Forecast Report form.

2. Current Year

   - For the current year, operators may report their forecasts based on the latest GFE/MRC submission.

3. Net Cumulative Balance

   Operator's Forecast Reports must identify the net cumulative balance of the OS Project for the current calendar year.

   The following net cumulative balance rules apply for Projects with an effective date before January 1 of the current calendar year:

   - If the Project did not reach payout by December 31 of the year prior to the current calendar year, the net cumulative balance is as reported on the previous year's EOPs.
   - If the Project reached payout by December 31 of the year prior to the current calendar year, the net cumulative balance is, if applicable, the net loss carried forward from the Period prior to January 1 of the current calendar year.
   - For Projects whose effective date falls within the current calendar year, the net cumulative balance is the prior net cumulative balance (PNCB).

4. Production Volumes

   - Forecasts of cleaned crude bitumen production volumes at the Royalty Calculation Point (RCP) are required.
   - The operator must provide the following information on the quality of cleaned crude bitumen:

     a. Average or a range of density in kg/m3 gravity
     b. Sulphur content (in weight%) and
     c. TAN - Total Acid Number. TAN is the number expressed in milligrams (mg) of potassium hydroxide needed to neutralize the acid in one gram of oil (mg KOH/g).

Note

> For those Projects that predict substantial capital additions towards the end of the 15 years forecast period, operators must provide additional notes/comments in the 'additional notes section' of the form indicating the nature of expansion, timing, and incremental production capacity expected.

5. Bitumen Price – Forecasts for unit price of cleaned crude bitumen price at RCP

6. Diluent - Forecasts for:

   a. Diluent volumes used at RCP - Type of Diluent, and

b. Diluent Price - Pricing Location

7. Other Product Revenues (must specify the products)

   a. Other product revenues include the Operator's Forecast of revenues from oil sands by-products such as sulphur and coke.

   b. "Other product revenues" and "other net proceeds" are mutually exclusive.

8. Total Natural Gas Volumes Used for Bitumen Production

   a. Projects that use natural gas must report the total volume (including solution gas volumes used, if applicable).

   b. For cold production Projects report the fuel gas used.

9. Solution Gas Volume Used (GJ/year)

   a. If the Project does not measure or estimate solution gas, put N/A in the "Solution Gas Volume Used" line

10. Natural Gas Price ($/GJ): Forecasts for natural gas purchase price.

11. Allowed Costs

   - Forecasts of both capital costs and operating costs are required.
   - **Capital costs** must be classified as strategic or sustaining:
     - Strategic capital: Capital expenditures that are required to construct and commission oil sands approved Project's initial bitumen production capacity or expand its production capacity.
     - Sustaining capital: Capital expenditures to maintain production of the Project at a certain level including costs for replacement of production wells.
   - **Operating costs** exclude the cost of natural gas and diluent.

12. Other Net Proceeds

   - Other net proceeds (ONP) generally refers to any considerations received or receivable during the period from the sale, lease, license or other disposition of any substances or assets (excluding oil sands products derived from the Project's development area) or technology of the Project. For example, it includes revenues from custom processing, cogeneration and other sources that are not related to the disposition of oil sands products. For a comprehensive definition of ONP refer to the OSRR'09 Section 23.

13. Forecast of the Project Payout Date

   - Projects that have not yet reached payout must provide a forecast of the expected Project payout date.

14. Additional Notes

   - Use this section if further clarifications or explanations are needed, such as costs to reduce greenhouse gas emissions.

7.6.3 Amendments

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 41

The Department recognizes that Operator's' Forecasts are "best guesses" at the time they are submitted, and can vary significantly in the coming years. The Operator's Forecast Report for a particular year can be amended until March 31 of the following year. Thereafter, operators can incorporate their revisions in the current year's report

7.6.4 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 37

Operator's' Forecasts must be submitted by November 30 of each year. If the 30th falls on a non-business day, the next business day will be the due date.

Failure to submit, or late submission of an Operators forecast may result in late filing penalties. (OSRR09 – Section 44) and interest (OSRR09 - Section 45) (See section 7.11 "Penalties" and section 7.12, "Interest").

7.7 Ad Hoc Reports

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 40

The Department may, by written notice, require the Project operator to provide additional information that may be relevant to calculating, determining, specifying, prescribing or verifying any amount, factor or other component that is used in the calculation of royalty or royalty compensation.

The written notice must specify:

- The deadline for the submission of the requested report(s)
- The frequency with which the report(s) may be required

It is the responsibility of the Project operator to ensure that the requested ad hoc Project report(s) reach the Department by the specified due date(s). Late filing penalties may be imposed if the required reports are late and may also incur interest. (OSRR'09 – Section 44) (OSRR'09 - Section 45) (See section 7.11 "Penalties" and section 7.12, "Interest")").

7.8 Enhancement Reporting

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 38.1

7.8.1 Cost Analysis & Reporting Enhancements (CARE)

In 2006, the Department announced to industry that additional information would be required from OSR Project operators. This information is essential for collecting appropriate royalties and effectively managing the development of Alberta's oil sands resources. This information will enable the Department to better report oil sands activities to Albertans and will aid in ensuring that decisions regarding oil sands development and royalty are made based on a comprehensive information basis.

Unless the Minister directs otherwise, the operator of a Project is responsible for the provision of the information in CARE. In some cases, the information called for in the report may not be available to the Project operator because it is controlled by joint venture partners, or some other party. The Minister may require that the person in possession furnish the report to the Minister and be accompanied by a statement of approval.

The CARE reporting data will not be subject to individual audit by the Department, but may be used to identify areas where reporting inconsistencies may have occurred. The CARE COST forms (workbooks) must reconcile to the annual reports (EOPS), which are subject to audit by the Department.

All CARE reporting forms (workbooks) are available on the Department's website in Excel and PDF formats (From the Department's website (http://www.energy.alberta.ca/), navigate to "Oil Sands," then "Forms."), Note all forms must be submitted electronically in Excel format through the secure web application Electronic Transfer System (ETS). Refer to section 7.9– "Royalty Reporting Formats and Timing" and Appendix H for ETS - File Naming Conventions.

NOTE:

> These Excel workbooks will be downloaded into a database – therefore no revisions to the form's format are allowed. CARE form formats must be standardized to allow macros to gather relevant data elements and complete calculations therefore; OSD has locked the form formats to ensure data integrity.

An online training module is available for the submission process: http://training.energy.gov.ab.ca/Pages/default.aspx. To access the portal, click on the provided link, and select Correspondence and then scroll to view the training modules

Correspondence	The Correspondence functionality is an online service that enables clients to receive or send data to the Department of Energy through a secure connection. Clients may retrieve the status of their correspondences using the Request Status Screen.
CARE Reporting	CARE Online Training provides the procedures for submitting Cost Analysis and Reporting Enhancements (CARE) forms to the Alberta Energy.

7.8.2 Glossary of Terms

A CARE Glossary of Terms (Refer to Appendix D) has been developed to aid operators in understanding the definitions for the data elements and has been structured to match individual CARE forms (workbooks).

7.8.3 Key Reasons for Information Reporting

7.8.3.1 Project Assessment and Tracking:

- This reporting will assist the Department in understanding and assessing new Projects and Project amendment applications in a timely and informed manner through access to pertinent operations and cost databases (e.g. benchmarking).
- Subsequent reporting will allow the Department to track the evolution of approved Projects, thereby ensuring that their implementation is in accordance with the original Project approval.

7.8.3.2 Royalty Collection and Verification:

- This reporting will ensure that oil sands royalties are collected in a timely and accurate manner in accordance with the Oil Sands Royalty Regulations: OSRR97, OSRR09, BVMR, and OSACR, the OSR Guidelines and the Project description and conditions of each OSR Project Approval.

7.8.3.3 Policy Development and Forecasting:

- This reporting will assist the Department in regular assessment of the effectiveness of the existing royalty regime.
- This reporting will support the Department's policy development, strategic planning and forecasting processes by improving our understanding and analysis of the relevant business environment and trends.

7.8.4 Timing – CARE Filing Timeline and Timetable

Effective 2015 reporting, CARE Revenue and WCS reports are reported on a quarterly basis. The filing deadline for CARE Revenue and WCS reports are on Feb 20, May 20, Aug 20 and Nov 20 of the year. CARE Cost and Subsurface reports, from 2015, are reported on an annual basis. The filing deadline for CARE Cost reports is on Apr 30 of the following year and for CARE Subsurface reports is on June 30 of the following year.

OSR Project Suspended but not Revoked:

CARE filing are required until the OSR Project is revoked.
Operators may write to the Director, Royalty and Tenure Operations, for consideration of a filing exemption if their Project is to be suspended for a long period.

7.8.5 Cost Data

The following is a brief summary of the CARE filing requirements. The Department will apply reporting enforcement provisions under OSRR'09 to any operator not furnishing these reports to the Minister as specified.

7.8.5.1 Capital Cost Data – Mining and In-Situ Projects

Capital costs incurred by, or on behalf of, the lessee or operator of the approved oil sands Project must be reported quarterly, and contain cumulative year-to-date information. Costs are reported in four categories, representing the stages of the life-cycle of an OSR Project. This is similar to the OSR Operators Forecasting reporting requirements:

- Initial PNCB
- Strategic Capital
- Sustaining Capital
- Reclamation/Abandonment

7.8.5.2 Operating Cost Data

Operating costs incurred by, or on behalf of, the lessee or operator of the approved oil sands Project must be reported quarterly, and contain monthly cumulative year-to-date information. Oil sands Projects have been segregated into two groups with different reporting details, as follows:

- In-Situ Projects
  - Well Operations
  - Cleaning Emulsion (Cold Production)
  - Cleaning Emulsion & Water Treatment (Thermal Production)
  - Steam Generation
- Mining Projects
  - Mining
  - Extraction and Tailings
  - Upgrading and Diluent Recovery Unit
  - Utilities [Utilities and Off-sites (UO)/Electrical Services (ES)]

7.8.6 Project Data Workbook: Volumetric, Operations, Reserves, Deposit and Reservoir Data Reports

7.8.6.1 Reserves Data – Mining & In-Situ Projects

Reporting of the initial Project area's proven and probable reserves, and remaining proven and probable reserves, completed on an annual basis on June 30th.

The calculation of reserves is based on gross reserves prior to royalty determination, and is prepared in accordance with a recognized reserve evaluation method, such as the Canadian Oil & Gas Evaluation Handbook (COGEH) or the Petroleum Resources Management System by the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC) and Society of Petroleum Evaluation Engineers (SPEE). Similar terminology is used by various securities regulators; however, we stress our information should not be confused with or compared to reporting for securities purposes.

This form must be submitted annually for the preceding fiscal Period. The Reserves form may be filed on an OSR Project basis or on a defined Project area. If the operator chooses to file on a defined Project area, a plat map is required with this form depicting the Project area with corresponding township, range and section identified

For existing OSR Projects, the Initial Proven Reserves and the Initial Proven plus Probable Reserves are data elements that the Department will use to establish historical values for the OSR Projects or defined Project area and must be reported as at December 31, 2008 or at an earlier date defined by the operator. For newly approved OSR Projects the effective date of the reserves calculation would be the approval date of the Project.

7.8.6.2 Deposit Data – Mining Projects

This form reports mining Projects' oil sands deposit information, and is filed upon initial assessment and updated with changes due to a Project expansion or addition of leases (when a material change has been identified by the operator).

7.8.6.3 Reservoir Data – In-Situ Projects

This form reports in-situ Projects' oil sands reservoir information and is filed upon initial assessment and updated with changes due to a Project expansion or addition of leases (when a material change has been identified by the operator).

Note: Deposit and Reservoir Data Forms

Operators are reminded to file as follows:

1) Report in prescribed metres (m).
2) Report in both the 'Range' and 'Average' columns.
3) Reported oil saturation and density in the CARE data and in the OSR Project applications data must reconcile.
4) Horizontal and vertical permeability should be reported as different values.
5) Oil saturation should be reported as a volume percentage (not weight percentage).
6) Reported net pay thickness should not be greater than the reservoir thickness.
7) Report reservoir area according to the following definition: Reservoir area is defined as the area used to determine the bulk volume of crude bitumen deposit measured in m2.

- For land based approvals, the reservoir area is the entire OSR Project area.
- For well based approvals, the reservoir area is the well drainage area.

8) ETS comment box
9) Data fields are restricted to numeric values only without measurement notation (i.e., %, ^ or *106, should not be used) or acronyms (i.e., ASL – above sea level, should not be used) which makes data processing difficult.

7.8.6.4 Operations Data – Mining & In-Situ Projects

At an OSR Project level, this form reports annual operations information, such as the number of site employees and emissions data. For integrated Projects with both bitumen production and upgrading facilities this data must be reported separately for each facility; or if reported on an AER scheme approval basis then the allocation methodology used must be documented.

- Filed Annually – June 30th

Note:

Data elements that are “grayed out” on the form are not required reporting at this time, as the Department is working with other government bodies in an effort to minimize reporting efforts.

7.8.6.5 Volumetric Data – Mining & In-Situ Projects

At an OSR Project level and AER scheme approval number level, this form reports annual volumetric data for both Integrated and Non-Integrated Projects. This data is used primarily by Oil Sands Operations, Project Engineering & Approval section, for the pre-approval analysis of the proposed Project or Project expansion, to determine Project viability and for forecasting. All measurements are standardized as reported to the Alberta Energy Regulator (AER) and are identified specifically in the AER Directive 017 – Measurement Requirements for Oil & Gas Operations.

- For integrated Projects with both bitumen production and upgrading facilities this data must be reported separately for each facility.
- Filed Annually – June 30th

Note:

Data elements that are “grayed out” on the form are not required reporting at this time as DOE are working with other government bodies in an effort to minimize reporting efforts.

7.8.7 Revenue Data Workbook

Filed quarterly

- Refer to Appendix E for the “CARE Timelines and Timetable” for filing details.
- Operators are required to carry forward previous quarter data into the current quarter form. Therefore, the 4th Quarter will contain a full year of data and will minimize the number of amendment submissions to previous quarters.

7.8.7.1 Cover Page

Effective with the 2011 reporting Period, the CARE – Revenue reporting has been streamlined into one Revenue workbook. A cover page has been added to help reduce the number of keying requirements and facilitate drop down selection lists. The following have been implemented in the cover page:

a. All streams currently reported on CARE forms will be included in the drop down list. If a new stream is created or does not appear in the list, the “unassigned stream” option can be chosen. Note that stream abbreviations are restricted to a 10 character length.

b. Data validation ensures that data is standardized across industry. Enter the quarterly quality measures:

   - TAN (provide in mgKOH/g - single number data entry, no ranges will be accepted),
   - Sulphur (provide sulphur in wt% data entry),
   - Density (Kg/m3 data entry).

c. Minimizes data entry:

   - Stream, Operator Name, Operator ID, Current Reporting Period auto-populate to each subsequent form.

d. Bitumen density clarification (Bitumen Blend Netback Calculation):

   Bitumen Density (Cleaned Crude Bitumen) – Density is – a measure of the mass of a substance per unit of volume the mass occupies and is, usually reported at standard temperature and pressure (STP). For bitumen, the density measurement is the value derived from a representative bitumen sample that has been prepared and measured according to generally accepted standard practices (i.e., ASTM4052). Provide the density of the cleaned crude bitumen in kg/m3.

7.8.7.2 Bitumen/Bitumen Blend Revenue – In-Situ Projects

On a stream level basis, this form reports detailed monthly sales of bitumen or bitumen blend.

a) Month of Sale and Product Type are selected from the drop down lists (Use ‘Notes’ section if Product Type does not appear in the drop down list).

b) Non Arm’s Length (NAL) and Arm’s Length (AL) sales reported as volumes which replace the reporting of the percentage of AL sales (from 2009/10 forms).

c) Handling Charges are reported as one monthly total for all AL volumes transacted in the month and one monthly total for all NAL volumes transacted in the month for the stream.

d) Slop volumes shipped and where revenue compensation is received, then report these volumes in the ‘Notes’ section.

7.8.7.3 Bitumen Blend Netback Calculation – In-Situ Projects

On a stream level basis, this form reports monthly bitumen blend volumes crossing the RCP. Other variables reported are diluent volumes, shrinkage volumes and transportation costs used in the netback calculation.

a) Month of Sale and Diluent Type are selected from the drop down lists (Use 'Notes' section if Diluent Type does not appear in the drop down list).

b) Diluent volumes reported reflect the diluent contained in the bitumen blend at the royalty calculation point (RCP)

7.8.7.4 Transportation Costs – In-Situ Projects

On a stream level basis, this form reports reporting of detailed monthly transportation costs incurred.

a) Month and Product are selected from drop down lists.

b) The transportation cost refers to aggregated transportation costs based on actual invoices or cost of service and product movement related to a title transfer location.

c) Transportation costs refer to the invoiced amount for the transportation for that month and does not necessarily equate to the Handling Charge reported in the GFE/MRC forms.

7.8.7.5 Diluent Supplied to a Stream – In-Situ Projects

On a stream level basis, this form reports details of all information relating to diluent supplied to a bitumen blend stream.

a) Month of Sale and Diluent Type are selected from the drop down lists (Use 'Notes' section if Diluent Type does not appear in the drop down list).

b) Diluent Volumes to be reported are actual purchases or diluent supplied from the internal diluent pool(s) to the OSR Project(s) for stream blending purposes.

c) This diluent volume does not necessarily equate to the diluent contained in the bitumen blend at RCP. Report the volume in cubic metres. This does not have to match the GFE/MRC forms

d) Diluent volumes reported reflect actual purchases or diluent supplied from internal diluent pool(s) to the OSR Project(s) for stream blending purposes.

7.8.7.6 Other Oil Sands Products Revenue – Mining and In-Situ Projects

On a stream level basis, this form reports for both mining and in-situ Projects of detailed monthly sales of other oil sands products.

- Month to be selected from a drop down list.

7.8.7.7 Western Canadian Select (WCS) Sales

Operators that have WCS sales are required to file this form.

- Filed quarterly

7.9 Royalty Reporting Formats and Timing

7.9.1 Oil Sands Report Submissions Using Energy's Electronic Transfer System (ETS)

Royalty and related reports must be submitted using the Department's secure web application, Electronic Transfer System (ETS). This includes the submission of monthly (MRC, GFE and NPR) and annual (EOPS) royalty forms, the Cost Analysis and Reporting Enhancements (CARE) reports (Revenue, WCS Sales, Cost, Subsurface), the Operator's Forecast, and related reporting (Statement of Approval, Independent Auditor Opinion, Cost Allocation Methodology Report, etc.). The royalty forms and related Statement of Approvals, Independent Auditor Opinion, and Cost Allocation Methodology Reports are submitted through ETS Oil Sands Royalty Reporting. The CARE Revenue, WCS Sales, Cost, Subsurface and Operator's Forecast Reports are submitted through the ETS Oil Sands Supplemental Reporting. Details on the ETS submission process and the reporting forms are available on the Department website (http://www.energy.alberta.ca/OilSands/814.asp), under Oil Sands Royalty Reporting, Reporting Resources for Operators.

Recent amendments provide authority for the Minister to publish royalty information for each oil sands Project according to Section 26.1(1) of *Mines and Minerals Administration Regulation*, starting in 2017 in respect of the 2016 production year. These amendments also give the Minister the authority to publish royalty information for crude oil and natural gas wells benefiting from strategic royalty programs under the Modernized Royalty Framework.

Royalty and related reporting forms can be downloaded from the forms pages on the Department website as PDF or Excel files. The PDF version, if available, is provided as example only.

Operators of a Project, non-Project well event or non-Project mining operation are required to use only ETS for their royalty and related reporting submissions. Inquires can continue to be emailed to the OS Reporting Mailbox (OSReport@gov.ab.ca), or you can contact the "Oil Sands Royalty Account Inquiries" team, see Appendix G, "Contact Information".

7.9.2 ETS Access

Operators of a Project, non-Project well event or non-Project mining operation must have an ETS Account with the Department in order to submit royalty reports.

To get access to the Electronic Transfer System, an ETS account Set Up / Change Form must be submitted to the Department. The form is available from the ETS site, under Apply for Access. Check "Oil Sands Royalty Reporting" for access to royalty reporting. Check “Correspondence CARE Forms and Operator’s Forecast” for access to supplemental reporting.

To access the ETS site, click on the ETS – Electronic Transfer System link in the Energy home page http://www.energy.gov.ab.ca/index.asp or directly access the site using http://www.energy.gov.ab.ca/OurBusiness/1076.asp

For an overview of the services available through ETS, see the ETS Overview. For more details about confidentiality, security and ETS availability, see the Client Account Handbook.

Additionally, an online training module is available for the submission process. (Energy Online Training Portal) To access the portal, click on the provided link, select ETS Accounts, and then scroll to view the training modules.

7.9.3 Required Information

The following table provides a summary of the Project identification and signatures required on royalty reporting forms:

PRE-PAYOUT		POST-PAYOUT	
Monthly Royalty Calculation (MRC)	End of Period Statement	Monthly Good Faith Estimate (GFE)	End of Period Statement
OSR Project name	OSR Project name	OSR Project name	OSR Project name
the oil sands Project number (OSRxxx)	the oil sands Project number (OSRxxx)	the oil sands Project number (OSRxxx)	the oil sands Project number (OSRxxx)
Operator Name and Operator ID	Operator Name and Operator ID	Operator Name and Operator ID	Operator Name and Operator ID
the report month (which corresponds to the current production Period (year and month))	the Period start and end dates	the report month (which corresponds to the current production Period (year and month))	the Period start and end dates
the name and contact information for the person who completed the report	the name and contact information for the person who completed the report	the name and contact information for the person who completed the report	the name and contact information for the person who completed the report
Date Prepared	Date Prepared	Date Prepared	Date Prepared

PRE-PAYOUT		POST-PAYOUT	
Monthly Royalty Calculation (MRC)	End of Period Statement	Monthly Good Faith Estimate (GFE)	End of Period Statement
Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or a person approved by the Minister in advance.	Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or a person approved by the Minister in advance.	Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or a person approved by the Minister in advance.	Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or a person approved by the Minister in advance.
due by the last day of the month following the production month	due within three months of the end of each Period	due by the last day of the month following the production month	due within three months of the end of each Period
Submit through ETS*	Submit through ETS*	Submit through ETS*	Submit through ETS*
N/A	auditor's letter required if crude bitumen measured at the RCP average more than 1,590 m3/day	N/A	auditor's letter required if crude bitumen measured at the RCP average more than 1,590 m3/day
Notes: 1) must be approved in advance by the Department (refer to IB 2009-03) 2) CFO – Chief Financial Officer 3) ETS – Electronic Transfer System			

7.9.4 Reporting Standards

All royalty-related reports submitted to the Department must comply with the following standards.

7.9.4.1 Volumetric Reporting

Volumes of bitumen, diluent and synthetic crude oil are expressed in cubic metres (m3) to the nearest tenth of a cubic metre. For example: 66.9 m3.

Quantities of sulphur are expressed in tonnes to the nearest tenth of a tonne. For example: 34.9 t.

7.9.4.2 Monetary Values

Monetary values are reported in Canadian dollars. The mathematical accuracy required for reporting monetary values is as follows:

- The unit price of oil sands products and diluent is expressed in dollars and cents to the nearest cent per unit (e.g. $123.45 per unit).
- Dollar amounts (except unit prices) reported on good faith estimates (GFEs) and EOPS are expressed to the nearest dollar (e.g. $123).
- Dollar amounts on pre-payout monthly royalty calculation forms shall be expressed in dollars and cents to the nearest cent (e.g. $1,235.45).

7.9.4.3 Negative Values

Negative values, whether monetary or volumetric, are indicated with a leading negative sign (e.g. –$132.50 or -133.5 m3).

7.9.5 Submissions

The Department is not liable for report submissions that are lost in transit.

It is the responsibility of the Operators of a Project, non-Project well event or non-Project mining operation to ensure that Project/Non-Project royalty reports reach the Department by the specified due dates. Penalties and interest may be imposed if required reports are late. (See section 7.11 “Penalties” and section 7.12, "Interest”)

The software used must be compatible with the version of Excel used by the Department. As of printing, this is Microsoft Excel 2010 or previous Excel versions.

7.9.6 Timing

Oil Sands Royalty Regulation, 2009, sections 33(1), 33(2), 31(9), 37, 38, 38.1, and 39

Monthly royalty reports—both pre-payout MRCs (monthly royalty calculations) and post-payout GFEs (good faith estimates)—are due by the last day of the month following the production month. For example, production and royalty for April would be reported by May 31. If the due date falls on a non-business day, the next business day will apply as the due date. However, for a payment due by the last day of March, the payment is due on the last day in March on which the offices of the Department are open.

For newly approved or amended OSR Projects that have retroactive effective dates, the first monthly report is due by the last day of the month following the month in which the Project was approved. For example, a Project approved in March might have an effective date of January. In this case, monthly reports for January, February and March would be due by the end of April. Due dates for subsequent monthly reports would follow the regular schedule.

End of Period Statements (for both pre- and post-payout Projects) are due within three months of the end of each Period.

Operator's Forecasts are due by November 30th of each year.

CARE reporting – refer to Appendix E for CARE reporting due dates.

For Pre-Payout Projects, Crown royalty payments must be submitted by the last day of the month following the month in which the Crown's royalty share of an oil sands product was delivered to the RCP. For example, if the Crown's royalty share of crude bitumen delivered to the RCP (and transferred to the lessee) in January was 300.0 m3, royalty in respect of that product is payable on or before February 28. (See section 4.4 – "The Royalty Calculation for Pre-Payout Projects").

For post-payout Projects, Crown royalty payments on end of period royalty adjustments must be submitted by the last day of the 4th month following the Period in which the Crown's royalty share of an oil sands product was delivered to the RCP. For example, if the Crown's royalty share of crude bitumen delivered to the RCP (and transferred to the lessee) in the Period 2018 was 400.0 m3, royalty in respect of that product is payable on or before April 30, 2019.

Post-payout Projects are required to make instalment payments each month. (See section 4.5 – "The Royalty Calculation for Post-Payout Projects").

Replacement reports are required to be furnished to the Minister accompanied by a statement of approval.

Note

> Penalties may be imposed if required reports are submitted late. Interest will be charged on penalties and royalties not paid on time. (See section 7.11 "Penalties" and section 7.12, "Interest")

7.10 Royalty Payment

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 29, 31, and 33

7.10.1 Application of Payments

Mines and Minerals Administration Regulation (262/1997) section 23

If compensation is owed to the Crown the money shall be applied against an operator's account under this Regulation or the Prior Regulation in the following order:

a) first, against amounts owing to the Crown that remain unpaid,

b) 2nd, against fees owing to the Crown by the person;

c) 3rd, against penalties owing to the Crown by the person;

d) 4th, against interest owing to the Crown by the person;

e) 5th, against rentals owing to the Crown by the person;

f) 6th, against amounts owing to the Crown by the person to increase a deposit or security maintained by the person;

g) 7th, against royalty amounts owing to the Crown by the person.

7.10.2 Methods of Payment

All remittances in respect of Crown royalty must be payable to the Government of Alberta.

- If the due date falls on a non-business day (weekend or any other day that government offices are closed), then the next business day will apply as a due date, except:
- In the case of payments due by the last day of March, royalty payments must be submitted on or before the last day in March on which the offices of the Department are open.

Crown royalty can be remitted in three ways:

- by cheque through the mail, or by courier, or dropped off at the Alberta Energy offices:

  Alberta Energy / Environment and Parks

  Main Floor Mail Room, North Petroleum Plaza

  9945-108 Street NW Edmonton, Alberta Canada T5K 2G6

  Or

  Alberta Energy, Calgary Information Centre AMEC Building

  300, 801 - 6 Avenue SW

  Calgary, Alberta Canada T2P 3W2

For this payment method, the total remittance must be less than $25 million. Payment allocation information must accompany the cheque payment at the time of deposit. See Payment Allocation Requirements for details.

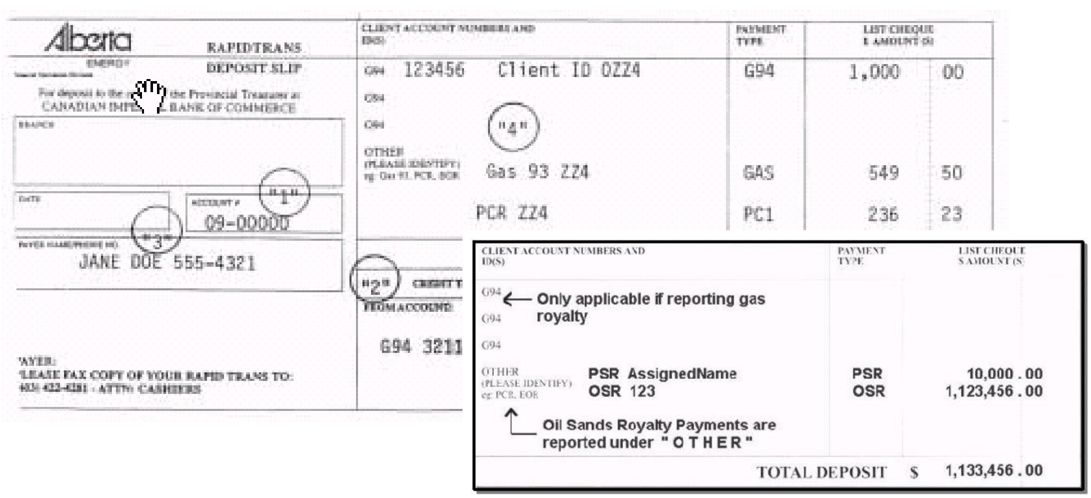
- by Electronic Funds Transfer (EFT) to the account of the Government of Alberta:

Bank Name:	Canadian Imperial Bank of Commerce (CIBC)
Beneficiary Name:	PT-Mineral Revenue Account
Bank Address:	10102 Jasper Avenue Edmonton Alberta T5J1W5
Bank No:	10
Swift Code:	CIBCCATT
Transit No:	59
Account No.	00-54305

Payment allocation information must be sent to Alberta Energy Financial Services Branch on or before the day of the deposit. See Payment Allocation Requirements for details.

- by deposit payment at designated CIBC branches, using a RapidTrans deposit slip:
    - Clients can deposit the payment at two designated CIBC branches in Calgary (Bow Valley Square 2 and Bankers Hall). A RapidTrans deposit slip is required for this method of payment. RapidTrans deposit slips can be obtained from Alberta Energy offices in Edmonton and Calgary.
    - If the client has a CIBC bank account number for RapidTrans, deposit the payment into that account. If the client does not have its own CIBC bank account number for RapidTrans, deposit the payment into the generic bank account: Transit 00009 Account 09-35603.
    - Payment allocation information must be reported on the RapidTrans deposit slip. A copy of this deposit slip must be sent to Alberta Energy Financial Services Branch on or before the day of the deposit. See Payment Allocation Requirements for details.

Figure 1: The information required for oil sands royalty payments.



Pre-authorized automatic debit remittance (Auto-Debit) may not be a viable payment option for all oil sands Crown royalty. Auto-Debit require remittance on or before the 5th last working day of the month. Operators may not know the oil sands Crown royalty payment by this date for this payment option. However, operators who are interested in the Auto-Debit payment option can consult with Alberta Energy Financial Services Branch for set up procedures. See Assistance with Remittances for details.

7.10.3 Payment Allocation Requirements

To enable accurate allocation of payments to accounts, payment allocation information must accompany each payment. The payment allocation information must be received by Alberta Energy Financial Services Branch on or before the day of the deposit or the payment may be returned or applied to activity id(s) determined by Alberta Energy.

There may be interest implications when deposits are returned or when deposits are transferred back to the correct activity id(s) due to missing or inaccurate payment allocation details provided to Alberta Energy.

The payment allocation information must contain the activity id(s) and payment amount(s). If a remittance contains payments other than oil sands Crown royalty, the activity id(s) for those payments must be indicated. The total payment allocations must reconcile to the remittance or they may be allocated as determined by Alberta Energy. There may be interest implications associated with the resulting allocations.

- For payments mailed or delivered to Alberta Energy offices, the payment allocation information must be provided on the cheque stub or on a separate document attached to the cheque.
- For RapidTrans deposits, the payment allocation information muse be provided on the RapidTrans deposit slip and a copy of the information must also be sent on the day of the deposit, via fax to Alberta Energy Financial Services – Cashiers at fax number: (780) 422-4281 or email:G94depositgov.ab.ca.
- For Electronic Funds Transfers, the payment allocation information must be sent on the day of the deposit, via fax to Alberta Energy Financial Services – Cashiers at fax number: (780) 422-4281 or email:G94deposit@gov.ab.ca.

Example of a Payment Allocation Summary:

Operator Name	######
Operator Id	######
Remittance Reference	########
Remittance Date:	YYYY-MM-DD
Remittance Amount:	$4500

Activity ID		Payment Allocation
OSR	####	$3500
CSR	####	$1000
NPR	####	$500
Total Allocations		$4500

7.10.4 Assistance with Remittances

For assistance with payment options and/or remittances, contact Alberta Energy Financial Services Branch at (780) 427-8857 or (780) 427-3600.

Additional copies of the RapidTrans deposit slips are available at the Alberta Energy Calgary Information Centre.

7.10.5 Accounts with Credit Balances and Credit Transfers

Unless otherwise directed, credit balances will be retained in the same account

(Project/Activity Id), but will not accrue interest, and will be applied to future month's Crown royalty compensation, interest or penalties owing. At Alberta Energy's discretion, account balances may be applied to offset other payables of the operator or lessee.

If an operator does not wish to keep a credit balance in an account to offset against the next month's payables, the operator may:

- Request to refund the balance or,
- Request to transfer the credit to another account (Project/Activity Id)

Requests should be sent to the Oil Sands Report Mailbox – OSReport@gov.ab.ca. For account transfers, please allow three business days for processing by Alberta Energy. If the credit transfer is to offset an upcoming payment, please ensure the request is made at least three business days prior to the payment due date. Interest may apply if the transfer cannot be completed by the payment due date as a result of late notification to Alberta Energy.

If the credit is the result of an End of Period Statement (EOPS) refund for the initial End of Period filing, requests to transfer the credit will not be accepted prior to the last day of the fourth month following the end of the Period

Notwithstanding any of the preceding, Alberta Energy reserves the right to:

- Refund any credit balance at any time or,
- Use its discretion to apply payments in accordance with section 46 of OSRR'09, and prior to the issuance of a refund may reallocate credits to set- off against any amount owing to the Crown by the operator pursuant to section 46(4) of the MMA. Interest may apply to any resulting underpayments.

7.11 Penalties

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 44

- Section 44(1) provides that a penalty of $5000 may be imposed on the person (typically an operator/lessee), who is required to furnish any report, statement of approval, or auditor's opinion other than CARE reports and ad-hoc reports, for failure to do so for each month or part of the month during which the failure continues. No penalty shall be imposed on outstanding statement of approval or auditor's opinion if the report for which they relate to has already been assessed a penalty.

The reporting person is required to file all reports regardless of the values reported, and in the format prescribed by the Minister.

The regulation provides that the Minister may impose a penalty or waive a penalty imposed on being satisfied that the failure to furnish a report, statement of approval or auditor's opinion by the deadline was due to circumstances beyond the control of the person required to furnish the said document. The following are the guidelines used by the Department in imposing and waiving a penalty:

1. The penalty amount of $5000 per month will be applied to the following reports, statement of approval or auditor's opinion if not submitted by the

required due date (see 7.11.1 OSR Due Date Chart - Royalty Reports):

- Operator changes under section 36,
- Operator's forecasts under section 37,
- Monthly Royalty Calculation (MRC), including statement of approval, under section 38,
- Good Faith Estimate (GFE), including statement of approval, under section 38,
- Non-Project Royalty (NPR) reports under section 38, and
- End of Period Statement (EOPS), including statement of approval and auditor's opinion under section 39.

If a person is required to furnish information to the Minister under section 27(6) and fails to do so by a specified time, the Minister may impose a penalty of not less than $1000 and not more than $5000 for each month or part of a month during which the failure continues.

2. A grace period of 3 working days maximum may be given to each report, statement of approval or auditor's opinion before a penalty is imposed pursuant to section 44(1). If the required report, statement or opinion is not received within the 3-day grace period, the full penalty of $5000 will be imposed for each month or part of the month the report, statement or opinion is late.

   - If the reporting person has been notified by the Department that an amendment is required, and the amendment report is not received by the last day of the month following the month in which the notification was given, the report will be considered missing and a penalty will be assessed.
   - Amendment or replacement reports, which the Minister may require a reporting person to furnish under section 41(2) of OSRR 2009, are not subject to a grace period since those reports are in response to a direct instruction from the Minister. A replacement report must be submitted on the due date specified by the Minister on the notice to the reporting person.

3. A penalty that has been imposed may only be waived for a month or part of the month if the person responsible for the preparation and/or submission of a required report is directly affected or impacted by circumstances beyond his/her control. Those circumstances, which must be verifiable by the Department before a penalty is waived, include the following:

   - Serious medical emergencies, which are conditions that require immediate medical attention by a health professional in order to prevent significant and long-lasting effects on physical or mental health of the person directly affected.

- Force majeure, which are extraordinary events or circumstances that prevent the person from the timely fulfilment of his/her reporting obligations (e.g., strike, riot, fire).
- Acts of God, which are natural events or occurrences that could not have been prevented by the person even with the exercise of foresight or caution (e.g., tornado, flooding).

Failure to submit a report, statement or opinion due to the person responsible being on vacation is not an acceptable reason for waiving a penalty.

4. Although the delegate of the Minister may decide otherwise, for CARE reports required under sections 38.1(1) and (1.1), a penalty of less than $5000 on the first month may be imposed in accordance with the following schedule:

Number of days late	Penalty amount ($)
5 working days or less from the end of the grace period	$1000
>5 working days but <=10 working days from the end of the grace period	$2000
>10 working days but <=20 working days from the end of the grace period	$3000
>20 working days but <=1 month from the end of the grace period	$5000
> 1 month from the end of the grace period	$5000 per month

5. Certain reports require a statement of approval or auditor’s opinion to be filed along with the report by the reporting deadline. If a reporting person (typically an operator) has already been penalized for failing to file a report, he will not be further penalized for failing to file the accompanying statement of approval or auditor’s opinion. However, if a report is submitted to the Department accurately and by the due date, but without the required statement of approval or auditor’s opinion, then a penalty will be charged for the missing statement and/or auditor’s opinion.

6. While the reporting person may have the option of submitting a statement of approval for each report or a single statement of approval indicating which reports the approval applies to, a penalty of $5000 per month will be imposed on each report whose corresponding statement of approval is not received on the filing deadline.

7. A penalty will be assessed against a reporting person who fails to provide

any required ad hoc reports (section 40) that the Department requested. Ad hoc reports may include other supporting documentation for a royalty calculation, such as supporting details for a unit price calculation. Once the reporting person is advised by the Department of a reporting deficiency or has been requested to supply additional information, the reporting person must supply the information within the timeframe identified in the Department's request.

- Ad hoc reports are not subject to a grace period, and carry a $5000 penalty for each day during which the failure to report continues. However, the penalty may be waived if the failure was due to circumstances beyond the control of the person responsible for providing the report.

8. A penalty may also be assessed against a reporting person (typically an operator) who does not comply with the regulation. If an audit (see Chapter 7.14) conducted by the Department identifies a royalty underpayment, and if the auditor determines that the underpayment occurred as a result of improper record keeping, negligent reporting procedures or non-compliance with the regulation, the reporting person would be notified that the cause of deficiency must be corrected.

- If the same deficiency arises in a subsequent Period(s), a penalty may be assessed. The penalty for the second instance is 10% of the resulting royalty deficiency. For any subsequent instances, the penalties would be 50% of the royalty deficiency.
- No penalty would be levied if the penalty amount is less than $1000.

9. Penalties must be paid within 30 days of receiving the notice of the penalty, or interest will be calculated on unpaid penalty amounts. Likewise, the Department will endeavor to immediately correct a penalty that has been imposed in error to the operator.

Note

> Penalties levied by the Crown on an OSR Project are not an allowed cost of the OSR Project under the OSAC.

7.11.1 OSR Due Date Chart - Royalty Reports

Royalty Report	Due Date
Monthly Royalty Calculation (MRC)	Last day of the month following the production month
Monthly Good Faith Estimate (GFE)	Last day of the month following the production month
Non-Project Well Royalty	Last day of the month following the production month
End of Period Statement (EOPS)	Within three months following the end of period
Operator's Forecasts	November 30th of each year
CARE Reports	Due Date
CARE – Cost Workbooks for both In-Situ and Mining (Allowed Cost/EOPS Reconciliation, Capital and Operating Costs)	Quarterly – Year to Date and Detailed by Month 1st Qtr – May 20 2nd Qtr – Aug 20 3rd Qtr – Nov 20 4th Qtr – April 30 of the following year
CARE – Revenue Workbook	Quarterly – Year to Date and Detailed by Month 1st Qtr – May 20 2nd Qtr – Aug 20 3rd Qtr – Nov 20 4th Qtr – Feb 20 of the following year
CARE – Project Data Workbook for both In-Situ and Mining	Annually - Year to Date June 30th of the following year
Western Canadian Select Revenue	Quarterly – Year to Date and Detailed by Month 1st Qtr – May 20 2nd Qtr – Aug 20 3rd Qtr – Nov 20 4th Qtr – Feb 20 of the following year
CARE – Statement of Approval	For CARE – COSTS & REVENUE Workbooks: 1st Qtr - May 20th of the period 2nd Qtr - Aug 20h of the period 3rd Qtr - Nov 20th of the period 4th Qtr - Feb 20th of the period (REVENUE Workbook) 4th Qtr - April 30th of the following year (COSTS Workbook)

7.12 Interest

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 45

7.12.1 Interest Charged by the Crown

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 45 (1), 45(2), and 45(3)

Interest may be charged to Project and non-Project operators who fail to remit royalty or other payments to the Crown by the dates prescribed in the Regulation. Note that interest due to or from the Crown for Periods prior to 2009 is determined under the Oil Sands Royalty Regulation, 1997.

Interest on some outstanding amounts is calculated from the first day after the payment due date until the amount is paid to the Crown.

Outstanding amounts (due to non-payment or underpayment) subject to this interest calculation include:

- A royalty payment from a non-project mine under OSRR'09 section 26(4),

An excess amount required to be paid under section 27(1.3) when a non-Project well determining a royalty share under the Petroleum Royalty Regulation, 2017 (PRR 2017), is approved as part of a Project.

- A royalty payment (NPR from a non-project well event under OSRR09 section 27(4),
- Pre-payout OSR royalty under OSRR'09 section 33(1),
- Post-payout OSR monthly royalty installment payment under OSRR09 sections 33(6)
- A provisional royalty assessment under OSRR'09 section 43(3) or section 43(4.1)(a),
- A penalty required to be paid under OSRR'09 section 44, and
- Any interest required to be paid under OSRR'09 section 45.

For post-payout Projects, the following amount, if those amounts are not more than 10% of the aggregate royalty payable for the Period.

- The amount by which royalty payable for the Period exceeds the amount paid by installments as identified in the EOPS, or
- The amount of an underpayment of royalty identified by a recalculation by the Minister under the Act including audit assessment. (Section 38 and 39 of the MMA).

If those amounts are more than 10% of the aggregate royalty payable to the Crown in respect of the Period, interest may be payable from the first day following the half–way point of the Period until the amount is paid to the Crown, on those amounts.

Note

> In calculating interest for a Period, if the Period includes the effective date of the Project, interest should be computed from the day that follows the effective date by half the number of days between the effective date and the last day of the Period, rather than from the first day of the 7th month of the Period. This modifies the “half year” rule to a “half period” rule when the Period is not a full calendar year.

If the Minister considers that a calculation made under section 6(3) or an estimate made under section 38(7) is incorrect due to Minister’s error, and the Minister corrects the calculation or estimate through a subsequent calculation, the Minister may refund any portion of the interest related to the incorrect calculation.

7.12.2 Interest Payable by the Crown

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 45

The Crown pays interest to Project operators or the lessees of non-project mines or non-project well events if certain payments due to those individuals are not made by the dates specified in the Regulation. The Crown pays interest on balances in the following circumstances:

- Where an amount is owed to the operator of a post-payout Project by the Crown regarding GFE overpayments under OSRR’09 section 33(11). In this case, interest is computed from the day following the last day of the Period in respect of which the amount was required to be paid.
- Where for post-payout Project, a royalty overpayment is identified in the EOPS (royalty paid by installments exceeds the royalty payable for the Period), or a royalty overpayment is identified as a result of a recalculation by the Minister under the Act, section 38 and 39, interest is computed from the date following the last day of the 4th month following the Period.
- The amount of any overpayment of a disputed amount computed from the date following the last day of the month when the overpayment was paid.
- Where an amount is owed to an operator of a Project based on recalculation of a provisional royalty amount. In this case, interest is computed from the first day from the second month following the month in which the Minister notifies the operator of the recalculation.
- Where a non-project mining or well event lessee has overpaid royalty compensation in respect of a month. In this case, interest is computed from the first day of the second month following the month in which the overpayment was made.

In each of the above cases interest is calculated until the date the Minister requisitions a cheque for the amount payable, or notifies the operator to deduct the amount payable from an amount to be paid by the operator under the Regulation.

Note

For clarification: the Minister's obligation is simply to requisition or request the cheque. The obligation to pay interest does not extend to the date the cheque is actually issued; once the cheque has been requisitioned, no further interest is payable.

If the Minister made a mathematical, clerical or systems error in a calculation under the Act and the Minister corrects such error, the Minister may reverse any portion of the interest paid related to erroneous calculation.

7.12.3 The Rate of Interest Charged or Paid

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 45(7)

In calculating interest payable to or by the Crown, the rate of interest in respect of any day is the yearly rate that is 1% higher than the interest rate established by the Province of Alberta Treasury Branches as its prime lending rate on loans payable in Canadian dollars that is in effect as of the first day of the month in which that day occurs.

An "Interest Rate Table" is available on the Department's website (http://www.energy.alberta.ca/Pages/default.aspx) navigate to "Oil Sands," then "Oil Sands Royalties" then " Interest Rates"). The interest rate table on this page.

7.13 Refunds

Operators that have an overpayment balance within their account may offset future months' royalty compensation with this credit balance within a reporting Period, or may make formal written request to the Department for refund of the balance. This formal request can be sent by e-mail to the OS Reporting Mailbox at OSReport@gov.ab.ca

7.14 Audits

Mines and Minerals Act – M17, section 38

Oil Sands Royalty Regulation, 2009, section 18

Oil Sands Allowed Costs (Ministerial) Regulation, sections 3 and 6

All financial information submitted regarding an OSR Project is subject to an audit conducted by the Department. The audit ensures that claimed expenditures are:

- reasonable, and incurred and paid within 90 days after the expenditure becomes payable,
- eligible as allowed costs under the Regulation,
- reflect an actual financial transaction that is supported by appropriate documentation.

Audits must be conducted within four years of the date when information is filed. If an audit is initiated in the fourth year and is not completed, it can be extended into the next calendar year.

Project Records

> *Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 42*
> OSR Project owners and operators must maintain all records related to applications, reports or statements required under the Regulation. For more information, refer to Information Bulletin 2013-08: Change of Operatorship or Ownership; Clarification of Responsibilities and Entitlements

Purchasers of OSR Projects should be aware that, should they take over as operator of a Project, they will be responsible for providing or arranging for access to any financial information requested by the Department, including information relating to any Period before they were operator.

7.15 Statutory Requirements and Recalculation

Mines and Minerals Act – M17, section 38

Mines and Minerals Administration Regulation (AR 262/97), Section 16.1(2)

In accordance with section 38 of the Act and section 16.1 of the MMAR, the Minister may calculate, recalculate or make additional calculations respecting the Crown's royalty share of a mineral or any royalty proceeds. A calculation, recalculation or additional calculation may be made in two ways:

- On the Minister's initiative in conjunction with an audit or examination; or
- At the written request of an operator/lessee.

Where the calculation, recalculation or additional calculation of any royalty proceeds is made pursuant to a written request or as a result of an audit or examination under section 47(5), and the written request is received or the audit or examination is commenced in the fourth year, that four year period is extended by one year.

8. Advance Rulings and Discretionary Allowed Costs

8.1 Advance Ruling Process

An advance ruling is a statement by the Department on how it will interpret the applicable Act, regulations, policies and guidelines with respect to specific, proposed business arrangements or specific allowed costs related to an OSR Project. This may include costs related to but not limited to: research conducted jointly between project owners or costs that may be shared between projects or project owners set out in some form of a business arrangement. (See Section 5.7) It may also include questions related to piloting of new technologies on OSR Projects, or treatment of revenue from oil sands products in transactions with affiliated and third party upgraders and refineries.

The Department will act in accordance with the advance ruling unless circumstances arise that are described in section 8.1.4 (Ruling Ceasing to Have Effect). The Department will issue an advance ruling only for proposed transactions that are being seriously considered by the Project owner.

The issuance of an advance ruling is based on full and complete disclosure of all facts, authorities and other matters relevant to the matter involved. Failure to meet these standards will invalidate the ruling.

Note

> Advance rulings should not be confused with applications for discretionary allowed costs, which are made under section 5 of the OSAC. There are significant differences between the two things. A discretionary cost application allows the Minister to approve allowed costs that are not specifically excluded, not specifically included, and not considered fundamental. An example might be a new technology or operation not previously contemplated under the existing legislation. This is contrast to an advance ruling, which interprets the current legislation, policies and guidelines in light of new business arrangements or technologies.

8.1.1 Requesting an Advance Ruling

Project owners or operators must submit a request each time an advance ruling is required (See Request for Advance Ruling or Discretionary Allowed Cost Form in Appendix K). A request for an advance ruling is to be submitted to the Director, Oil Sands Operations. (See Appendix G, "Contact Information").

The request must be identified as a “Request for Advance Ruling” and signed by an authorised representative of the party seeking the ruling.

8.1.2 Statement of the Issue

The request should clearly state the issues on which a ruling is required and the purpose of the contemplated arrangement. A request for advance ruling must include the following information contained in the Request for Advance Ruling and Discretionary Allowed Costs form (Appendix K):

- A clear statement of the issue for which the ruling is required including an explanation of the purpose of a proposed business arrangement or a description of the costs of a proposed capital asset.
- A comprehensive analysis of the effect of each of the relevant facts;
  - detailed references to the relevant provisions of the enactments of authority having a bearing on the issues involved; and
  - the Project operator's interpretation of those enactments and the authorities that form the basis of that interpretation.
- Contact information.
- Additional details as appropriate.

8.1.3 Review and Ruling Process

After initial review of the material provided, the Department may call for additional information or clarification of the material provided by the Project operator. Requests will be handled in the order in which they are received.

The Department reviews the submitted material, and in some cases may request additional information or clarification. In most cases, the Department issues its ruling within 45 days. More time may be needed for the Department to issue an advance ruling on particularly complex issues.

Once approval is granted, it may specify the terms and conditions that must be met in order for the approval to remain active. Further, the approval of a request may also specify the term of the approval, and in alignment with section 38(6) of the MMA, an approval may be granted retroactively for up to 5 years.

A request for an advance ruling may be withdrawn at any time before the ruling is issued.

8.1.4 Ruling Ceasing to have Effect

The Department may retroactively revoke an advance ruling in the following circumstances:

- where there has been a misrepresentation or omission in the statement of facts or purpose, or any other misrepresentation has been made to the Department with respect to the proposed arrangements; and

- where there has been non-compliance between the proposed business arrangements, for which the advance ruling was sought, and what actually transpired.

Where the law upon which the ruling was based on changes, the ruling will cease to be effective as of the date of the change in law; and

Where government policy changes, the ruling will cease to be effective as of the date the Project operator is so notified.

8.2 Discretionary Allowed Costs Process

Discretionary allowed costs are costs which require approval by the Minister under section 5 of the OSACR. These may be costs which have been incurred, are being incurred or will be incurred in the future. The Minister may, upon application by the operator, approve these costs as allowed costs of the OSR Project.

A discretionary allowed cost is one that is directly related to a Project and that is not a specifically excluded cost , specifically included cost, or considered a fundamental cost of a Project (See section 1(1)(k, I, h) of the OSACR).

The Minister may establish a term for the approval of a discretionary allowed cost and impose conditions to which the approval is subject. The Minister may revoke approval if the conditions are not met.

8.2.1 Application for Discretionary Allowed Costs

Requests for discretionary costs must be made by Project operator. Project operators must submit a request each time an approval is required.

All requests must be directed to the attention of the Director, Resource Development Policy. (See Appendix G, "Contact Information") and must be signed by an authorized designate of the Project owner.

A request for discretionary allowed costs must include the following information contained in the Request for Advance Ruling and Discretionary Allowed Costs form (Appendix K):

- A clear statement of the cost for which the approval is required.
- An explanation of the purpose for and a description of the costs.
- Contact information.
- Additional details, as appropriate.

The approval of a discretionary allowed cost is based on full disclosure of all relevant information.

8.2.2 Review Process

After initial review of the material provided, the Department may call for additional information or clarification of material provided by the Project operator. Requests will be handled in the order in which they are received. In most cases, the Department issues its ruling within 45 days. More time may be needed for the Department to rule on particularly complex requests.

8.2.3 Approval and Conditions

Section 5(2) of the OSAC states that the Minister may approve a discretionary cost if:

- as set out in section 5(2) and 5(3) of the OSRR09, the Request for Advance Ruling and Discretionary Allowed Costs form (Appendix K) is completed to the Minister's satisfaction (section 5(2)(a)(i) OSACR) ;
- there is no risk of overstated or unverifiable costs being included in the allowed costs of the Project (section 5(2)(a)(ii) OSACR); and
- the cost directly and materially benefits the Project and is not too remote from the Project (section 5(2)(b) OSACR).

The Department determines whether or not the costs are allowable by considering:

- Are the costs reasonable and incurred by or on behalf of the project owners?
- Are the costs directly attributable to the oil sands Project?
- Are the costs incurred and are they necessary to recover oil sands from the Project?
- Are the costs incurred within reasonable distance of the Project?

A discretionary cost must be reasonable, in amount, purpose and remoteness, in relation to the circumstances under which it is incurred. Reasonableness will be assessed by the department on a case-by-case basis.

Section 5(3) of the OSAC allows the Department to specify the terms and conditions that must be met in order for the approval to remain active.

Further, the approval of a request may also specify the term of the approval and in alignment with section 38(6) of the MMA an approval may be granted retroactively for up to 5 years and under the same section of the MMA any submissions may be reviewed at any time within that 5 year period.

An application for a discretionary allowed cost may be withdrawn at any time before the decision is issued.

8.2.4 Termination and Revocation

Section 5(4) of the OSAC allows for the termination or revocation of an approval.

The Department may terminate or revoke an approval at any time if a requirement set out in section 5(2) of the OSAC is not met or a term or condition in the approval has not been met or is not being complied with.

In the event that the Department terminates the approval, the cost is no longer considered an allowed cost effective from the date of termination. The applicant may submit a new request for discretionary allowed cost.

If a discretionary allowed cost is revoked by the Department then the cost is no longer considered an allowed cost effective from the date of the revocation or in some cases the revocation could take place retroactively. The applicant is not allowed to submit a new request for discretionary allowed cost.

9. Dispute Resolution

Mines and Minerals Dispute Resolution Regulation (AR 170/2015);
Mines and Minerals Act – M17, sections 38 and 39

In this chapter, the term “applicant” means the “Project owner”, “Project operator” or “lessee” (as those terms are defined in the applicable legislation), or the authorized representatives or any of them.

9.1 Objections

Mines and Minerals Dispute Resolution Regulation (AR170/2015), Section 2(1)

Oil sands Project lessees generally have the right to object to calculations or recalculations of oil sands royalty matters set out in the OSRR09, the OSACR and the BVMR.

Decisions related to Project approvals and amendments, PNCB, and other matters subject to the discretion of the Minister cannot be the subject of an objection.

9.2 The Dispute Resolution Process

The first stage in dispute resolution is information discussions between the Project owner and the Department. If the dispute cannot be resolved informally, the Project owner may file an objection. The objection process for oil sands Project owners is similar to that available to holders of conventional oil and gas leases

9.2.1 Filing of an Objection

Mines and Minerals Dispute Resolution Regulation (AR170/2015), Section 3

To dispute the decision made by the Department, the Project owner must submit a written objection to the Minister. (See Appendix G, "Contact Information")

The objection must be clearly identified as such. It must be signed by an authorized representative of the Project owner and include the following information:

- a copy of the notice from the Department which gives rise to the calculation or recalculation (e.g. audit assessment or audit report);
- a summary of the basis for the objection; and
- evidence that the amount under dispute has been paid, including penalties and interests that relate to the objection.

> Project owners must pay all disputed royalty amounts, including penalties and interests that relate to the disputed amount, assessed by the Department before they file an objection. [Section 2(3) of the MMDR] If their objection is successful, the appropriate amount will be refunded with interest.

An objection must be filed within 90 days from the end of the month that the Department sends a notice (e.g. audit assessment or audit report) advising of a calculation or recalculation.

When an objection is received, the Minister will determine whether or not it is in accordance with the requirements listed above and may accept or reject the objection. The Minister must provide written notice to the applicant that the Minister will review the objection.

9.2.2 Review of an Objection by the Minister

Mines and Minerals Dispute Resolution Regulation (AR170/2015), Section 4, 5 and 6

The Minister will, after accepting an objection, proceed to review the objection by considering the matters in dispute and consulting with the Department and the applicant. He may request additional information from either or both of the parties, which the parties shall provide in a timely fashion. The Minister may request any relevant information, including evidence, legislation and guidelines; and the analysis and position of the Department and applicant with respect to the objection.

However, the Minister may not request or consider information that was not considered by the Department when conducting an assessment, audit or review of the subject-matter objection. Therefore, it is incumbent on the applicant to provide the Department with all relevant information prior to the Department concluding an assessment, audit or review.

The Minister, after considering the merits of the objection, must issue a final decision not later than 180 days from the date he accepted the objection, by sending a copy of his decision to the applicant and the Department. This time frame may be extended if both the applicant and the Department agree.

9.2.3 Transitional Provisions

The committee process no longer exists and the Minister now makes the final decision. The transition rules for the dispute resolution process are as follows:

1. Operators with objections for which a proposed resolution has been issued prior to February 15, 2017 will not be affected by the MMDR amendments. Those objections will continue to be resolved under the former process (i.e., the committee process, if a committee is so requested and established under sections 6 to 11 of the MMDR Regulation).

2. For an oil sands objection made before February 15, 2017 for which a proposed resolution has not been issued, sections 6 to 11 of the MMDR Regulation (the committee process) will apply to any matter determined to be substantially the same as one for which a committee has been requested or established.
3. For an objection made on or after February 15, 2017, the new process will apply (i.e. no committee process available, Director's decision final).