

Alberta Oil Sands Royalty Guidelines

Principles and Procedures

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Alberta Oil Sands Royalty Guidelines

Principles and Procedures

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Table of Contents

Notice	viii
<i>The Act and the Regulations</i>	<i>ix</i>
<i>Related Legislation</i>	<i>ix</i>
About This Document	x
<i>Chapters and Appendices</i>	<i>xi</i>
<i>Additional Information</i>	<i>xi</i>
1. Alberta’s Oil Sands Royalty System	1-1
<i>1.1 Oil Sands Royalty: A Look Back.....</i>	<i>1-1</i>
1.1.1 The Impetus for Change	1-2
<i>1.2 Generic Oil Sands Royalty.....</i>	<i>1-2</i>
1.2.1 What Is “Generic” Royalty?	1-2
1.2.2 A “Revenue Minus Cost” Approach.....	1-2
1.2.3 Objectives	1-4
1.2.4 Applicability: Who Pays Generic Royalty?	1-4
1.2.5 Components of the Generic Royalty Regime.....	1-4
1.2.5.1 The Mines and Minerals Act.....	1-4
1.2.5.2 The Regulations	1-5
1.2.5.3 Regulatory Rules.....	1-5
<i>1.3 Alternative Royalty Regimes.....</i>	<i>1-5</i>
2. Oil Sands Royalty (OSR) Projects.....	2-1
<i>2.1 What is an OSR Project?</i>	<i>2-1</i>
2.1.1 Types of OSR Projects.....	2-2
2.1.1.1 New OSR Projects	2-2
2.1.1.2 OSR Project Amendments	2-2
2.1.1.2.1 Examples of OSR Project Amendments	2-3
2.1.1.2.2 Application in the Alternative	2-4
2.2 OSR Project Requirements	2-4
2.2.1 ERCB Approval.....	2-4
2.2.2 Exclusions.....	2-4
2.2.3 Minimum Considerations	2-5
2.2.3.1 Operational Integration and Common Management.....	2-5

2.2.3.2	Location Requirements	2-6
2.2.3.2.1	Project Components (Except Upgraders)	2-6
2.2.3.2.2	Geographically Contiguous	2-6
2.2.3.3	Project Economics	2-6
2.2.3.3.1	Economic Justification for Project Expansions	2-6
2.2.3.3.2	Economic Justification for Project Amalgamations	2-6
2.2.3.4	Protecting the Crown's Royalty Share	2-7
2.2.3.4.1	Crown Royalty and Project Amendments	2-7
2.2.3.4.2	OSR Project Amalgamations	2-8
2.3	<i>The Components of an Oil Sands Royalty Project Description</i>	2-8
2.3.1	The OSR Project Name	2-9
2.3.2	The OSR Project Application and Approval Order Number	2-9
2.3.3	The OSR Project Lessee(s)	2-9
2.3.4	Ownership Considerations	2-10
2.3.4.1	Freehold Interests	2-10
2.3.5	The OSR Project Operator	2-10
2.3.6	OSR Project Operations	2-11
2.3.6.1	Recovery Methods and Other Technology	2-11
2.3.6.2	Oil Sands Products	2-12
2.3.7	Lands, Leases and Mineral Rights	2-12
2.3.7.1	Project Leases	2-12
2.3.7.2	Project Lands	2-12
2.3.8	Core or Supporting Assets	2-13
2.3.8.1	Core or Supporting Asset Threshold	2-14
2.3.8.2	Partial Inclusion of Assets	2-14
2.3.9	Criteria for Inclusion of Wells Completed Prior to the Project Effective Date in an Oil Sands Royalty Project	2-14
2.3.10	The Effective Date	2-16
2.3.10.1	Subsequent ERCB Approvals and Effective Dates	2-16
2.3.11	Prior Net Cumulative Balance	2-17
2.3.11.1	Eligible Costs for PNCB	2-17
2.3.11.2	Pre-Project Royalty	2-18
2.3.11.3	Amounts excluded from PNCB	2-18
2.3.11.4	Amounts to be Deducted from the PNCB	2-18
2.3.11.5	Timing	2-19
2.3.11.6	Amendments to PNCB	2-20
3.	Applying for Generic Royalty Terms	3-1
3.1	<i>When Is an Application Required?</i>	3-1
3.2	<i>Who Can Apply?</i>	3-1
3.3	<i>The Application Process</i>	3-1
3.3.1	Consulting with the Department	3-1
3.3.2	Making an Application	3-2
3.3.3	Completing the Application in OASIS	3-3
3.3.3.1	"Application" Type	3-3
3.3.3.2	Project Ownership	3-3
3.3.3.3	Project Identification	3-4
3.3.3.4	Project Overview	3-4
3.3.3.5	Project Description	3-5
3.3.3.5.1	Energy Resources Conservation Board Approvals	3-5
3.3.3.5.2	Lands and Leases	3-6
	Project Lands	3-6
	Project Leases	3-6
3.3.3.5.3	Project Operations	3-6

3.3.3.5.4	Wells.....	3-7
3.3.3.5.5	Facilities and Other Capital Assets.....	3-7
3.3.3.5.6	Financial Information.....	3-8
3.3.3.5.7	Economic Evaluation Data.....	3-9
3.3.3.5.8	Signatures.....	3-13
3.4	<i>The Approval Process</i>	3-14
3.4.1	Pre-Screening Process.....	3-14
3.4.1.1	Pre-screen Process Flowchart.....	3-15
3.4.1.2	Pre-screen Process Timeline.....	3-15
3.4.2	Department Review.....	3-15
3.4.3	Project Approval: The Ministerial Order.....	3-16
3.4.4	Project Approval Process Timeline.....	3-16
3.5	<i>Project Revocation</i>	3-17
4.	Calculating Oil Sands Royalty.....	4-1
4.1	<i>The Royalty Calculation Point</i>	4-1
4.2	<i>Elements of the Royalty Calculation</i>	4-2
4.2.1	The Opening Balance.....	4-2
4.2.2	The Return Allowance.....	4-2
4.2.2.1	The Return Allowance for Pre-Payout Projects.....	4-3
4.2.2.2	The Return Allowance for Post-Payout Projects.....	4-3
4.2.2.3	The Return Allowance for Suspended or Abandoned Projects.....	4-4
4.2.3	Allowed Costs.....	4-4
4.2.3.1	Types of Allowed Costs.....	4-4
4.2.3.1.1	Reasonable Costs.....	4-5
4.2.3.1.2	Example of an Allowed Cost Determination.....	4-6
4.2.3.1.3	Example: Road Costs.....	4-6
4.2.4	Project Revenues.....	4-7
4.2.4.1	Types of Revenue.....	4-7
4.2.5	Unit Price.....	4-9
4.2.5.1	Third Party Dispositions Equal or Exceed the Third Party Disposition Threshold.....	4-10
4.2.5.2	Third Party Dispositions Do Not Meet the Third Party Disposition Threshold.....	4-10
4.2.5.3	Bitumen Valuation Methodology.....	4-12
4.2.5.3.1	Hardisty Bitumen Value.....	4-12
4.2.5.3.2	Calculating the Transportation Allowance for a Project's Bitumen.....	4-15
4.2.5.3.3	Examples of Transportation Rate Calculations for Removal and Diluent Pipelines.....	4-17
4.2.5.4	Examples of Oil Sands Unit Price and Project Revenue Calculations.....	4-22
4.2.5.5	Negative Unit Price.....	4-26
4.3	<i>The Royalty Calculation for Pre-Payout Projects</i>	4-26
4.4	<i>The Royalty Calculation for Post-Payout Projects</i>	4-28
4.4.1	Installments.....	4-31
4.5	<i>Examples of Project Configurations</i>	4-33
4.5.1	An OSR Project that Produces Raw Bitumen.....	4-33
4.5.2	An OSR Project that includes Processing Facilities.....	4-35
4.5.3	OSR Projects with Jointly Owned Processing Facilities.....	4-36
4.5.4	An OSR Project that Provides Custom Processing Services.....	4-37
4.5.5	Royalty Treatment of Bitumen Recovered from Waste Water.....	4-38
5.	Capital Assets and OSR Projects.....	5-1
5.1	<i>Capital Assets</i>	5-1
5.1.1	Capital Assets Included in OSR Projects.....	5-1

5.1.1.1	Core or Supporting Assets	5-1
5.1.1.2	Partially Includable Assets.....	5-2
5.1.1.3	Costs of Capital Assets in OSR Projects.....	5-2
5.1.1.4	Revenues from Capital Assets in OSR Projects.....	5-3
5.1.2	Summary Table: Treatment of Costs and Revenues	5-4
5.2	<i>Solution Gas and Off-Lease Fuel Gas</i>	5-5
5.3	<i>NAL Pipeline Services</i>	5-7
5.3.1	Calculating Costs for Non-Basic Pipeline Services	5-7
5.3.1.1	Allowed Cost Based on Fair Market Value	5-8
5.3.1.2	Allowed Costs Based on Cost-of-Service Calculations	5-8
5.3.2	Line Fill Costs.....	5-11
5.3.3	Cost Rules for Pipeline Overcapacity	5-12
5.3.4	Cost Rules for Capital Additions to Non-Basic Pipelines.....	5-13
5.4	<i>Cogeneration Plants</i>	5-14
5.4.1	Cogeneration Cost Allocation Rules.....	5-14
5.4.2	General Allocation and Cost Determination Steps	5-14
5.4.3	Valuing NAL Electricity and Steam	5-15
5.4.3.1	Fair Market Value for Electricity.....	5-16
5.4.3.2	Steam – Cost of Service Calculations for Steam Systems	5-16
5.4.3.3	Cost Treatment for Project and Non-Project Systems	5-16
5.4.4	Fuel and Component Allocations for Cogeneration Systems	5-17
5.4.4.1	Non-Gas Turbine Based, Combined Heat and Power (CHP) system	5-17
5.4.4.2	Gas Fired Turbine Combined Heat and Power Systems	5-19
5.4.5	Determining Capacity for a Steam Generating Unit	5-19
5.5	<i>Custom Processing</i>	5-20
5.6	<i>Hedges</i>	5-20
5.7	<i>Research</i>	5-21
5.7.1	Cost Rules for Research.....	5-21
5.7.2	Examples of Allowed Research Costs	5-22
5.7.3	Examples of Research Costs That Are Not Allowed	5-22
5.8	<i>Cross-Boundary Wells</i>	5-22
5.9	<i>Wells With Surface Locations Off Project Lands</i>	5-24
6.	Non-Arm’s Length Transactions and Affiliates.....	6-1
6.1	<i>Non-Arm’s Length Transactions</i>	6-1
6.1.1	Definition of Affiliate	6-1
6.1.2	Definition of Non-Arm’s Length Transaction	6-2
6.1.2.1	Ministerial Determination of Non-Arm’s Length Transactions.....	6-2
6.2	<i>Valuing Non-arm’s Length Costs</i>	6-3
6.2.1	Where a Fair Market Value can be determined	6-4
6.2.1.1	Transfer of Assets between Affiliated OSR Projects	6-5
6.2.2	Where a Fair Market Value cannot be determined, or a “basic service” must be valued	6-5
6.3	<i>Cost Rules for Non-Arms Length diagram</i>	6-6
7.	Administration and Enforcement.....	7-1
7.1	<i>Oil Sands General Form Information</i>	7-2
7.2	<i>Reporting Changes</i>	7-3
7.3	<i>Reporting Requirements - Non-Project OSR Calculation</i>	7-3

7.3.1	Non-Project Mining Operations.....	7-3
7.3.2	Non-Project Well Events	7-4
7.3.2.1	Determining the Crown Royalty Share	7-4
7.3.2.2	Timing.....	7-7
7.4	<i>Reporting Requirements for Pre-Payout Projects</i>	7-7
7.4.1	Monthly Royalty Calculation Reporting Forms.....	7-7
7.4.1.1	Amendments	7-11
7.4.1.2	Timing.....	7-11
7.4.2	End of Period Statement Reporting Forms (Pre-Payout).....	7-12
7.4.2.1	Contents of Pre-Payout Reporting Package	7-12
7.4.2.1.1	Statement Requirement (PRE-1)	7-12
7.4.2.1.2	Reason for Amendment (PRE-1a).....	7-13
7.4.2.1.3	Project Payout Status (PRE-2).....	7-13
7.4.2.1.4	Allowed Costs Summary (PRE-3 and PRE-3a).....	7-13
7.4.2.1.5	Return Allowance (PRE-4).....	7-14
7.4.2.1.6	Revenue Summary (PRE-5)	7-14
7.4.2.1.7	Revenue and Royalty Details (PRE-6)	7-15
7.4.2.2	Amendments	7-17
7.4.2.3	Timing.....	7-17
7.4.3	Reporting Requirements for Post-Payout Projects.....	7-18
7.4.4	Monthly Good Faith Estimates Reporting Forms	7-18
7.4.4.1	Timing.....	7-22
7.4.5	End of Period Statements Reporting Forms (Post-Payout).....	7-23
7.4.5.1	Contents of Post-Payout Reporting Package.....	7-23
7.4.5.1.1	Statement Requirement (PST-1).....	7-23
7.4.5.1.2	Reason for Amendment (PST-1a)	7-24
7.4.5.1.3	Royalty Payable (PST-2).....	7-24
7.4.5.1.4	Royalty Calculations (PST-3).....	7-24
7.4.5.1.5	Allowed Cost Summary (PST-4 and PST-4a).....	7-24
7.4.5.1.6	Other Net Proceeds (ONP) (PST-5)	7-25
7.4.5.1.7	Return Allowance (PST-6).....	7-25
7.4.5.1.8	Project Revenue (PST-7).....	7-25
7.4.5.1.9	Carry Forward Amounts (PST-8).....	7-26
7.4.5.2	Amendments	7-27
7.4.5.3	Timing.....	7-27
7.5	<i>The Operator's Forecast</i>	7-28
7.5.1	Operators Forecast Submission Procedures	7-28
7.5.2	Operator's Forecast Report	7-29
7.5.3	Amendments	7-31
7.5.4	Timing	7-31
7.6	<i>Ad hoc Reports</i>	7-32
7.7	<i>Enhancement Reporting</i>	7-32
7.7.1	Cost Analysis & Reporting Enhancements (CARE).....	7-32
7.7.2	CARE Glossary of Terms	7-33
7.7.3	Key Reasons for Information Reporting	7-33
7.7.4	Timing – CARE Filing Timeline and Timetable	7-34
7.7.5	Cost Data	7-35
7.7.5.1	Capital Cost Data – Mining and In-Situ Projects.....	7-35
7.7.5.2	Operating Cost Data.....	7-35
7.7.6	Project Data Workbook: Volumetric, Operations, Reserves, Deposit and Reservoir Data Reports 7-36	
7.7.6.1	Reserves Data – Mining & In-Situ Projects.....	7-36
7.7.6.2	Deposit Data – Mining Projects	7-36
7.7.6.3	Reservoir Data – In-Situ Projects	7-36
7.7.6.4	Operations Data – Mining & In-Situ Projects.....	7-37
7.7.6.5	Volumetric Data – Mining & In-Situ Projects	7-38

7.7.7	Revenue Data Workbook.....	7-38
7.7.7.1	Cover Page.....	7-38
7.7.7.2	Bitumen/Bitumen Blend Revenue – In-Situ Projects.....	7-39
7.7.7.3	Bitumen Blend Netback Calculation – In-Situ Projects.....	7-39
7.7.7.4	Transportation Costs – In-Situ Projects.....	7-40
7.7.7.5	Diluent Supplied to a Stream – In-Situ Projects.....	7-40
7.7.7.6	Other Oil Sands Products Revenue – Mining and In-Situ Projects.....	7-40
7.7.7.7	Western Canadian Select (WCS) Sales.....	7-40
7.7.8	CARE Statement of Approval.....	7-41
7.8	<i>Royalty Reporting Formats and Timing</i>	7-41
7.8.1	Oil Sands Report Submissions Using Energy’s Electronic Transfer System (ETS).....	7-41
7.8.2	ETS Access.....	7-41
7.8.3	Royalty Form Types for ETS Submission.....	7-42
7.8.4	Form Types for ETS Submission.....	7-42
7.8.4.1	Required Information.....	7-43
7.8.4.2	Reporting Standards.....	7-44
7.8.4.2.1	Volumetric Reporting.....	7-44
7.8.4.2.2	Monetary Values.....	7-44
7.8.4.2.3	Negative Values.....	7-44
7.8.4.3	Submissions.....	7-44
7.8.5	Timing.....	7-44
7.9	<i>Royalty Payment</i>	7-46
7.9.1	Application of Payments.....	7-46
7.9.2	Methods of Payment.....	7-46
7.9.3	Required Information.....	7-47
7.9.4	Information and Assistance.....	7-48
7.10	<i>Penalties</i>	7-48
7.10.1	OSR Due Date Chart - Royalty Reports.....	7-50
7.11	<i>Interest</i>	7-51
7.11.1	Interest Charged by the Crown.....	7-51
7.11.2	Interest Payable by the Crown.....	7-52
7.11.3	The Rate of Interest Charged or Paid.....	7-53
7.12	<i>Refunds</i>	7-53
7.13	<i>Audits</i>	7-53
7.14	<i>Statutory Requirements and Recalculation</i>	7-54
7.15	<i>Pre-2009 Inventory and Pre-2009 Transitional Inventory</i>	7-54
7.15.1	Transition from OSRR’97 to OSRR’09.....	7-54
8.	Advance Rulings	8-1
8.1	<i>Requesting an Advance Ruling</i>	8-1
8.2	<i>Required Information</i>	8-1
8.3	<i>Review and Approval</i>	8-2
8.4	<i>Rescinding an Advance Ruling</i>	8-2
9.	Appeals and Dispute Resolution	9-3
9.1	<i>Issues That May Be Appealed</i>	9-3
9.2	<i>Time Limits</i>	9-3
9.3	<i>The Appeal Process</i>	9-4

9.4	<i>The Dispute Resolution Process</i>	9-4
9.4.1	Requesting an Appeal	9-4
9.4.2	Review by the Director of Dispute Resolution	9-5
9.4.3	Requests to Establish a Dispute Resolution Committee	9-5
9.4.3.1	Selecting a Committee	9-6
9.4.3.2	The Role of the Committee	9-7
9.4.3.3	The Minister's Decision	9-7
9.4.3.4	Notification and Publication	9-7
9.4.3.5	Costs	9-7
9.5	<i>Informal Mediation of Project PNCB</i>	9-8

Appendix
Due to the size of this document Appendices A through I are under separate cover.

Notice

The guidelines outlined in this document are based on:

- the *Mines and Minerals Act, RSA 2000, c. M-17* (the Act),
- the *Oil Sands Royalty Regulation, 1997* (AR 185/97) (OSRR'97),
- the *Oil Sands Royalty Regulation, 2009* (AR 223/2008) (OSRR'09),
- the *Oil Sands Allowed Costs (Ministerial) Regulation* (AR 231/2008) (OSAC) and
- the *Bitumen Valuation Methodology (Ministerial) Regulation* (AR 232/2008) (BVMR).

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.

This is the first major amendment to the guidelines since November 1, 2006, and reflects the new regulations that came into effect on January 1, 2009: the *OSRR'09*, the *OSAC* and the *BVMR*. These guidelines reflect the Department's policies and procedures as of January 1, 2009 unless otherwise indicated. Stakeholders will be notified 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.

Readers are reminded the guidelines have no legislative sanction. Should the guidelines conflict with the *Act* or the *OSRR'97*, the *OSRR'09*, the *OSAC*, and the *BVMR*, the Act and regulations will prevail.

To the extent the guidelines conflict with any Department's Information Letters or Information Bulletins published prior to January 1, 2009 on any subject matter contained in the guidelines, the guidelines will prevail.

The Act and the Regulations

Copies of the *Act*, the *OSRR'97*, the *OSRR'09*, the *OSAC*, the *BVMR*, and related legislation are available through the Queen's Printer:

In Edmonton:	E-mail: qp@gov.ab.ca
Main Floor • Park Plaza	Web Site:
10611 – 98 Avenue	http://www.qp.alberta.ca/Laws_Online.cfm
Edmonton, Alberta T5K 2P7	
Phone 780.427.4952	
Fax 780.452.0668	

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
- Mines and Minerals Administration Regulation (AR 262/1997)
- Oil Sands Tenure Regulation (AR 50/2000)
- Oil Sands Dispute Resolution Regulation (AR 247/2007)
- 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)
- Petroleum Royalty Regulation, 2009 (AR 222/2008)
- Oil Sands Conservation Act, RSA 2000, c. O-7
- Oil Sands Conservation Regulation (AR 76/1988)
- Natural Gas Royalty Regulation, 2009 (AR 221/2008)
- Innovative Energy Technology Regulation (AR 22/2011)
- Drilling Royalty Credit Regulation (AR 245/2009)
- Métis Settlements Act RSA 2000, c. M-14

The following legislation continues to apply for limited purposes only:

- Oil Sands Royalty Regulation, 1984 (AR 166/1984)
- Oil Sands Royalty Regulation, 1997 (AR 185/1997)

About This Document

The Alberta Oil Sands Royalty Guidelines are designed to:

- Help oil sands developers understand and comply with the:
 - *Mines and Minerals Act, RSA 2000, c. M-17*
 - *Oil Sands Royalty Regulation, 1997 (AR 185/1997),*
 - *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).*
- Help oil sands developers 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 *Oil Sands Royalty Regulation, 2009 (OSRR'09)* 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 generic OSR terms.
- 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 (OSR) 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

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 'Our Business', then 'Oil Sands', then '[Oil Sands Contacts](#)'.

1. Alberta's Oil Sands Royalty System

The Alberta Crown owns 97% of oil sands mineral rights; freehold owners hold the remaining 3%. Mineral rights owned by the Alberta Crown are managed by the Department on behalf of the citizens of the province.

Oil sands tenure is the system through which Crown-owned oil sands rights are leased and administered. Alberta's tenure system generates revenue by granting the right to produce oil sands products.

Oil sands royalty is the system through which the Crown—as the owner of the province's oil sands—receives a share of the economic rent generated from the development of that resource. The Alberta Crown receives a royalty—a share of oil sands products produced or equivalent revenue—from the oil sands rights it leases to companies.

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 minimum royalty until an oil sands Project achieved profitability. 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 ranged from 1% to 5%. Royalty on net revenues (post-payout) ranged from 25% to 50%. Specific development, operating and capital costs were allowed and 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. And 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 to assess the technical, socio-economic, environmental and marketing aspects of oil sands development and recommend strategies to address these issues.

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 addition, since the royalty structure was not transparent, it was difficult for developers to evaluate investment plans.

In its 1995 report, the task force outlined a comprehensive new approach for Alberta's oil sands industry. A key recommendation 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. This generic approach to oil sands royalty would place all new OSR Projects on an equal footing. Standard royalty terms would create fiscal certainty and stability, and encourage oil sands investment.

The Government of Alberta accepted that recommendation of the task force and began work to develop a generic oil sands royalty regime, which incorporated many of the Task Force's recommendations.

1.2 Generic Oil Sands Royalty

Alberta's current generic oil sands royalty regime dates to July 1, 1997, when the OSRR'97 came into force. Effective January 1, 2009, to implement the New Royalty Framework, that regulation was replaced by the new OSRR'09, OSAC and BVMR Regulations.

1.2.1 What Is "Generic" Royalty?

The current oil sands royalty regime is called generic because the same, standard 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.

1.2.2 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 an OSR Project reaches payout, its **royalty rate** and **reporting obligations change**. In addition, the post-payout royalty calculation is variable. For example, if revenues fall, or if expenses 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 OSRR’09 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 part 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 a 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 a fair return to Albertans, who own the province's resources.
- create a stable fiscal and regulatory framework that facilitates oil sands development by private sector companies,
- 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 developers.
- 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 OSRR'09 (see Chapter 3, "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, RSA 2000, c. M-17
- The oil sands royalty regulations:
 - *Oil Sands Royalty Regulation, 1997* (OSRR'97);
 - *Oil Sands Royalty Regulation, 2009* (OSRR'09);
 - *Oil Sands Allowed Costs (Ministerial) Regulation* (OSAC), and
 - *Bitumen Valuation Methodology (Ministerial) Regulation* (BVMR).
- Policies, guidelines and business rules developed by the Oil Sands Strategy and Operations Division.

1.2.5.1 The Mines and Minerals Act

The *Mines and Minerals Act, RSA 2000, c. M-17* provides the general authority for the collection of Oil Sands Royalties, including audit and recalculation provisions.

1.2.5.2 The Regulations

The OSRR'09, OSAC, and the BVMR specify the details of the generic royalty regime, including:

- 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 (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)

Note: Each component is discussed in detail in the specified chapter of these guidelines.

1.2.5.3 Regulatory Rules

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

1.3 Alternative Royalty Regimes

Developers, who do not have an OSR Project approval under OSRR'09, pay royalty as “non-project” operators under OSRR'09 Division 1 of Part 4, 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* 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 Energy Resources Conservation Board (ERCB) 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 ERCB may also grant approvals for processing plants under section 11 and industrial development permits under section 12 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 OSRR’09 as a Project defined and approved by the Department for royalty purposes under section 11 of that Regulation.

A developer who wishes to pay royalty as a Project under the terms of the OSRR’09 must apply to the Department under section 10 (Applications). If the scheme or operation has been approved by the ERCB, and if a project application, submitted to the Department by the lessee, meets the requirements of OSRR’09, it may be approved as an OSR Project under section 11 (Approvals) of this Regulation.

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.

The 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”)

A Note on Terminology

An OSR **Project description** included as part of an OSR Project approval order specifies the lands, leases, operations and facilities that are considered to be “part of a Project” or “in 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**.

Details about the application and approval process are outlined in Chapter 3, “Applying for Generic Royalty Terms”.

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 and amalgamations)

2.1.1.1 New OSR Projects

OSR Projects are considered new if the Project approval under Section 11 of the OSRR'09 or Section 15 of the OSRR'97 (Prior Regulation) has not been previously issued. For example, non-project (well event) oil sands operations that previously paid royalty either under the *Oil Sands Royalty Regulation, 1984 (AR166/84)*, or Section 26 or 27 under OSRR'09, are 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** (See section 2.3 - [“The Components of an Oil Sands Royalty Project Description”](#)), which specifies the minimum requirements as:

- the lands and leases that have been approved as part of the OSR Project.
- the OSR Project operations, including the 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 ERCB approval orders) and capital assets.

2.1.1.2 OSR Project Amendments

Oil sands developers who wish to modify the terms of their OSR Project description must apply to the Department. If the application meets the requirements of the OSRR'09 (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 for:

- expansions, which involve the addition to or deletion of lands or facilities from the Project description
- reductions, which involve the removal of lands or facilities from the OSR Project description
- amalgamations, which combine two or more approved OSR Projects into a single OSR Project
- changes in recovery method or technology

OSR Project amendment applications are encouraged—but 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 at least notify the Department so that records and contact lists can be kept up to date. ([See section 2.3.5 “The OSR Project Operator”](#))

Ministerial Amendments

Pursuant to section 12, the Minister may in certain circumstances amend an OSR Project on the Minister's own initiative with notice to the operator.

Consulting with the Department

OSR project developers 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 from the OSR Project. (Any addition of assets, located other than on OSR Project lands, must be specified).
- 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.
- amalgamation of two or more existing OSR Projects.
- changes to the ERCB scheme approval (see note below).

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 ERCB. When an amendment to an ERCB 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 ERCB 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 Strategy and Operations. (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.

2.2 OSR Project Requirements

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

2.2.1 ERCB Approval

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

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 ERCB, as required under sections 10 to 15 of the *Oil Sands Conservation Act*.

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

ERCB application(s) and approval(s) must be filed with the Department as part of the application for OSR Project approval. The required ERCB 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 included in an ERCB-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 ERCB. For example, rights of ways for roads may be granted by Sustainable Resource Development, and ground water licences by Alberta Environment. 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 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 Periods the OSR Project is expected to be conducted.
- the maximum production capacity and the maximum period of time for expansion of the OSR Project's production capacity if the Minister has established such conditions for the OSR Project.

In issuing an OSR Project approval order, the Minister may take additional considerations 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 Period the OSR Project is expected to be conducted.

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 is reflective of existing operations, albeit carried out on a larger scale or larger production base order (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 the Crown royalty.

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 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 expenditure and production data are the same whether the OSR Project expansion is approved, or the expansion proceeds as a separate project
- 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.

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 Description

An OSR Project description will include:

- the OSR Project name,
- the OSR Project lessee(s) and their ownership interests,
- the OSR Project operator,
- the lands and leases that have been approved as part of the OSR Project,
- a description of the OSR Project operations, including the recovery method and technology that have been approved, the product or products that will be produced and the approved production capacity,
- a listing of the OSR Project facilities (including the required ERCB approval orders),
- the effective date of the OSR Project,
- the OSR Project's prior net cumulative balance (PNCB).

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.

The name assigned to an OSR Project should serve as a specific identifier (for example, Elk Point Project or Project ABC). The name should remain applicable for the duration of the OSR Project, regardless if owners, operators or OSR Project specifics change.

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) ([See section 3.3.2 "Making an Application"](#)), 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(s)

The OSR Project lessee(s) is an individual(s) or corporation(s) that has leased the right to develop and use oil sands resources from a defined land area or subsurface stratum. The extent and duration of the lessee's rights are specified in an oil sands agreement called a lease. The OSR Project lessee is also recognized as an OSR Project owner.

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 OSRR'09, 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) and Ad Hoc Reports. When an operator takes over a project or project lands the current operator is responsible for filing all forms 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

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 [7.10 – “Penalties”](#) and section [7.11 – “Interest”](#))

Oil Sands Royalty Regulation, 2009, section 44 and 45

The OSR Project operator may apply 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., waterflood, polymer flood, 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, metals, 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 ERCB zone designations or deeper rights reversion zone designations.

2.3.7.2 Project Lands

The surface areas included in a Project are 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) and 14(1)(c)

A core or supporting asset is an asset (or a facility) without which the oil sands or oil sands products to be recovered or obtained from a OSR Project could not be so recovered or obtained, or an asset required for the operations or maintenance of such assets. The major facilities and assets used by an OSR Project are specified and approved in the OSR Project approval order.

Facilities

Examples of OSR Project **facilities** include:

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

Assets

Examples of **assets** include:

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

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 that do not meet the requirements for OSR Projects. Approved OSR Project facilities and assets are specified in the OSR Project approval order. Facilities 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 long term is expected to (and continues to) meet or exceed the OSR Project use threshold of 75%.

2.3.8.2 Partial Inclusion of Assets

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

Only certain types of capital assets may be partially included in an OSR Project description and only as provided under OSRR'09. Currently the types of assets that can be partially included are: processing plants, co-generation plants, and cross-boundary wells.

When a processing plant is partially owned by the lessees of an OSR Project, the Minister may include in the description of the OSR Project a proportion of the plant that is the same proportion as the lessee's ownership of the plant.

If the OSR Project's use of a processing plant is not in the same proportion as its ownership, ONP or costs will result.

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 thermal energy or electricity will be used for the OSR Project, and the proportionate ownership of the plant by the OSR Project lessees.

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 is 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.

For a capital asset to be included in the description of a Project, the applicant must demonstrate the following:

- The asset is a core or supporting asset of the Project;
- The sustained use of the asset over the remaining useful life of the asset for the purposes of the Project as a percentage of the total use of the asset for all purposes is likely to equal or exceed the Project use threshold; and
- All the approvals required by law in relation to the asset are subsisting.

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 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 well trajectory and completion information for them to be considered for inclusion in the Project;
- 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;

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 OSRR'09.

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 ERCB approvals, complete cost and revenue data and OSR Project economic forecasts—has been provided. All required ERCB 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 ERCB approval relating to the proposed project or the amendment relating to the expansion is approved
- the first day of the month that precedes by 9 months the month in which the Project or the amendment relating to the expansion is approved

OSR Project applicants may wish to defer the effective dates of their projects. In this case, the Department may assign an effective date that is later than what would normally be assigned under the terms of OSRR'09.

- requests for a deferred effective date must be included with the OSR project application,
- required ERCB approvals must still be in place when the OSR project application is received.

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.

2.3.10.1 Subsequent ERCB Approvals and Effective Dates

Schemes, operations, and facilities that are approved by the ERCB 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 ERCB approvals, schemes, operations and facilities. Otherwise associated costs and revenues may not be considered as part of the royalty calculation.

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 ineligible costs 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 OSRR'09, an amendment to the PNCB balance will not normally 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)

The same rules apply to eligible costs in the PNCB and allowed costs as defined under the OSAC Regulation, except the OSAC applies to costs after the effective date of an OSR Project or OSR Project expansion while costs eligible for PNCB must be incurred prior to the effective date of an OSR Project or OSR Project expansion.

For costs incurred prior to the effective date to be considered as part of the PNCB costs, they must be incurred during the approved PNCB Period.

2.3.11.2 Pre-Project Royalty

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 15(2)(d) and section 26 or 27

Royalty incurred during the PNCB Period and paid to the Crown under the *Oil Sands Royalty Regulation, 1984 (AR 166/84)*, under section 26 or 27 of the OSRR'09, 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 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's expansion PNCB:

- costs incurred during periods in which oil sands development was substantially suspended or abandoned,
- costs that would not qualify as allowed costs (under OSAC) 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 invoices, receipts, contracts, timesheets or other like original documentation satisfactory to the Minister,
- the costs in respect of which Innovative Energy Technology Program (IETP) costs have been established,
- costs incurred to recover or obtain oil sands or oil sands products to which the *Experimental Oil Sands Royalty Regulation* applies, are not allowed costs,
- 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.

Note

Section 2(1) of the *Drilling Royalty Credits Regulation (AR 245/2009)* outlines the criteria required for a well to be eligible for drilling royalty credits (DRC). Subject to subsections 2(1)(c), (d), and (e), all the wells that were spudded and finished drilling on or after April 1, 2009 but before April 1, 2011 are eligible for the DRC. Pursuant to Section 2(2)(a) “a well is not eligible if the well is part of a Project, or is the subject of an application to be part of a Project under the *Oil Sands Royalty Regulation, 2009 (AR 223/2008)*”.

If a well was eligible for DRC and had been allocated a DRC, and that well later is included in an OSR application after the DRC program has ended, then the DRC will be accounted for through an adjustment to the prior net cumulative balance (PNCB). A deduction of \$200/m must be removed from the PNCB for each well that is in the application and was identified to receive DRC, regardless of who initially was provided the DRC. (See section [3.3.3.5.4, “Wells”](#))

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 usually limited to costs incurred within, or up to three years before the Project’s effective date. The Minister may allow costs incurred in the 4th and 5th years before the effective date if the applicant can demonstrate that steps to obtain the necessary ERCB approvals were being diligently pursued in that Period. Efforts towards obtaining ERCB approval could include consulting with the ERCB or local stakeholders.

Costs incurred more than five years before an OSR Project’s effective date are usually not eligible for inclusion in PNCB calculations. For example, the costs of delineation wells incurred more than 5 years before the effective date of a proposed OSR Project expansion are usually excluded from the PNCB. An exception may be made if the OSR Project owner can demonstrate that significant cost savings will result if the tangible assets to which the costs relate are used for the OSR Project. An example could be the use of an existing cleaning plant; or the recompletion of an existing evaluation well for an OSR Project purpose.

NOTE: An OSR Project applicant must specify the time frame within which the OSR Project’s PNCB was accumulated. Once this timeframe has been agreed upon, it cannot be changed.

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?

The generic OSR regime does not apply automatically – by default, royalty is payable under the OSRR'09 Sections 26, 27, and 28 as amended. Oil sands developers, 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 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 developers 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 Strategy and Operations. (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 OASIS (Oil Sands Administration & Strategic Information Systems) 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 Internet address: <http://www.energy.gov.ab.ca/>, from "Our Business", navigate to "Services", "[Electronic Transfer System \(ETS\)](#)"

OASIS is a comprehensive secure automated system that allows the Oil Sands Strategy and Operations Division 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 (<http://www.energy.alberta.ca/>), navigate to "Our Business", then "Services," then "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. Upon access to the portal, click on the provided link, select Knowledge Resources, and then scroll to the OASIS resource titles to view the training modules.

OASIS 01. - Training System Overview	<i>Module provides an overview of the Energy Online Training Portal and course structure for external users.</i>
OASIS 02. - ETS Account Setup and Preferences	<i>Module provides an overview of how ETS Accounts and Preferences are set up and maintained.</i>
OASIS 03. - OASIS Overview	<i>Module provides an overview of the OASIS Online Training as well as brief overview of the web-based system for submitting OSR Project Applications.</i>
OASIS 04. - OASIS Roles	<i>Module focuses on the various roles involved in submitting an OSR Project Application.</i>
OASIS 05. - Create New OSR Project Application	<i>Module provides the procedures for creating and submitting a New OSR Project Application.</i>
OASIS 06. - Create an Amendment OSR Project Application	<i>Module provides the procedures for submitting an amendment to an existing OSR Project or an amendment to a Pending New OSR Project.</i>
OASIS 07. - Manage Work in Progress	<i>Module describes the process for retrieving saved OSR Project Applications.</i>
OASIS 08. - Generate OSR Project Application Reports	<i>Module describes the various reports that can be generated for a new OSR Project Application.</i>

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. 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 all OSR Project lessees.

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.
- 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:

- ERCB 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 Energy Resources Conservation Board Approvals

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

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

If the approvals include specific terms or conditions required by the ERCB, this should be brought to the Department's attention. Related applications and approvals for separate facilities (e.g. central 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 ERCB 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:

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

Project Leases

- the lease number and lease description for all oil sands agreements to be included within the OSR Project,
- the subsurface strata (geological names and zone designations/deeper rights reversion zone designations) and deposits from which oil sands products will be recovered,
- deposits covered in an oil sands lease cannot be approved as part of an OSR Project unless the development of the deposits has been approved by the ERCB.

3.3.3.5.3 *Project Operations*

Applicants should provide:

- 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 NAL 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.
- information on development plans, future production profile or anticipated production profile.
- information regarding reservoir properties.
- process flow diagrams must be included with the description of OSR Project operations. These diagrams should indicate the design capacity of all major components.

3.3.3.5.4 Wells

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

Note

Applicants must indicate which (if any) wells in their proposed Project application were eligible for, and received, a DRC. (See section [2.3.10.1, “Eligible Costs for PNCB”](#)) [Refer to IB 2011-01 – “Application of Drilling Royalty Credits to Wells in an Oil Sands Royalty Application”](#).

3.3.3.5.5 Facilities and Other Capital Assets

Applicants must provide the following information about each facility and asset 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 will be located other than on OSR Project lands
- the function of the asset or facility
- the location of the asset or facility
- each lessee’s specific equity share of any capital assets material to OSR Project operations
- a description of all other assets that are expected to be of material relevance to OSR Project operations
- a description of the level of use of the assets for OSR Project and non-project uses
- the facility name and identification code, if available
- the appropriate ERCB approvals or permits

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.

3.3.3.5.6 Financial Information

Financial information submitted by an OSR Project applicant is treated as 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.

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 "Our Business," then 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. NOTE: 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.

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.

3.3.3.5.7 Economic Evaluation Data

All OSR Project applications for proposed projects must be accompanied by Economic Evaluation Data. 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.

OSRR'09 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: ERCB 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: administrative changes, such as a change of operator, do not.

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

- ERCB 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.
- 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.
- Opening unrecovered balance/PNCB – enter amount in dollars (Character limit of 99,999,999,999. Value input will be rounded to the nearest whole number.)
 - 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.
- Data in real dollars as of (enter year) - enter the year the real dollars refer to.
- Return allowance rate (000's) (percentage: a range between 0.00-10.00% is required).
- Density - provide cleaned crude bitumen density pre-blend in kg/m³ (a range between 800.00 – 1100.0 is required).
- Sulphur – provide cleaned crude bitumen sulphur 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 – 1.0 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.

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 June 2008, then the data in this table should start as of July 2008 (half-year) and then full years thereafter.
- Bitumen production volumes (m³) for the year.
- Number of producing wells for the year. Field not applicable for mining projects.
- Number of injector wells for the year. Field not applicable for mining projects.
- Bitumen price (C\$/m³).

- WTI (West Texas Intermediate) price (C\$/bbl).
- Net gas production/consumption (i.e., gas produced less consumed) (GJ) - enter gas consumption as negative.
- Natural gas price (C\$/GJ).
- Non-gas variable operating expenditure (Opex) (C\$/m³).
- Fixed Opex (C\$/well/yr) (000's) – operator has the option to report fixed operating cost in dollars per well per year (C\$/well/yr), or dollars per year (C\$/yr), or both (if applicable). Enter the amount in thousands of dollars.
- Other net proceeds (000's) - Enter the amount in thousands of dollars.
- Capital expenditures (000's) – Sustaining - enter the amount in thousands of dollars.
- Capital expenditures (000's) – Strategic - enter the amount in thousands of dollars.
- Capital expenditures – Abandonments/Reclamation (000's) - enter the amount in thousands of dollars. Enter reclamations cost and end of life liabilities at the end of the Project (including dismantling and decommissioning costs of production facilities).
- Number of abandoned wells per year. Field not applicable for mining Projects.

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 to:

Do not require decimal places

No. of Producing Wells
 No. of Injector Wells
 Net Gas Production/Consumption (GJ)
 No. of Abandoned Wells

1 decimal place

Bitumen Production Volumes (m³)

3 decimal places

Fixed Opex (C\$/well/yr) (000's)
 Fixed Opex (C\$/yr) (000's)
 Opening Unrecovered Balance (000's)
 Other Net Proceeds (000's)
 Gross Revenue (000's)
 Crown Royalty Based on Gross Revenue (000's)
 Crown Royalty Based on Net Revenue (000's)
 Crown Royalty Payable (000's)
 Total Operating Costs (000's)
 Capital Expenditures – Strategic (000's)
 Capital Expenditures – Sustaining (000's)
 Capital Expenditures – Abandonments/Reclamation (000's)

Unrecovered Balance Before Return Allowance (000's)

Unrecovered Balance After Return Allowance (000's)

5 decimal places

Gross Royalty Rate

Net Royalty Rate

The Economic Evaluations Data 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 "Our Business," then to "Oil Sands," then "Forms."), however all submissions of the Economic Evaluations form must be made through the secure web application Electronic Transfer System (ETS) in Excel format.

3.3.3.5.8 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
- confirm the applicant's willingness to comply with the provisions of the OSRR'09

3.4 The Approval Process

3.4.1 Pre-Screening Process

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 5(2), 5(3), 10(1), 10(2), 10(3) and 10(4)

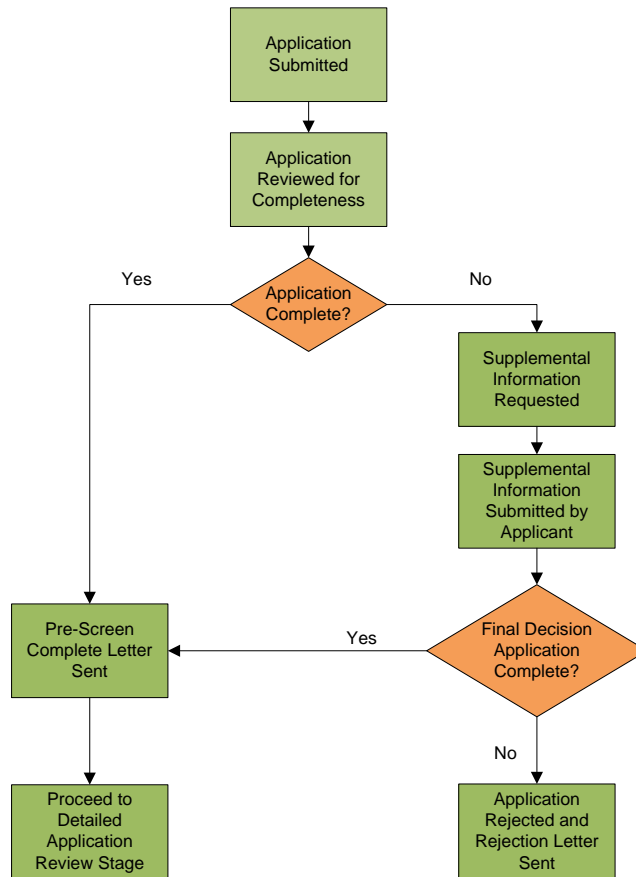
Applications which do not fully satisfy the requirements of Section 10(2) or 10(4) may be deemed incomplete and rejected, under Section 10(6)(a) of OSRR'09. The Project Engineering and Approvals Unit will assess applications and provide Project operators with an opportunity to remedy any deficiencies in their applications before rejecting them. An application pre-screening process and timeline has been implemented. The process and timelines are as follows:

- a) The applicant submits an application that complies with subsections 5(2), 5(3), 10(1), 10(2), 10(3) and 10(4) of OSRR'09.
- b) The Department begins the pre-screen review process upon receipt of the application. The pre-screen review process should take ten business days.
- c) 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.
- d) At the end of the ten day response period, 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), and written notice provided to the applicant.

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

Timeline (business days)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	
Application submitted																							
Pre-screen review																							
Pre-screen response																							
Final completeness decision																							

3.4.2 Department 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.

3.4.3 Project Approval: The Ministerial Order

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

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.
-

Confidentiality

These 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 OSRR'09 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 their Project Approval or the Minister may (by order) revoke an OSR Project approval, Prior Approval, or an order made under Section 12 of the OSRR'09.

The Minister may revoke an OSR Project Approval, Prior Approval, or order 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 wilful 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 has been abandoned, or
- all 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.

The Department will:

- provide written notice at least 30 days before revoking an approval or order, notifying 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,
- the lessees of the agreement shall comply with any terms and conditions in the order effecting the revocation.

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 OSRR'09. Under Alberta's OSR regime, royalty is paid in one of two ways. Projects pay either a gross revenue royalty or net revenue royalty depending on the status of the Project.

Non-project oil sands producers pay royalty according to Division 1 of Part 4 of the OSRR'09. The Crown's royalty share from non-project wells is calculated according to the *Petroleum Royalty Regulation, 2009*, and the 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, and is 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 crude bitumen, which is then processed in a processing plant (not part of the OSR Project) to obtain clean crude bitumen prior to its disposition, then the RCP is the outlet of that processing plant.

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:

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

4.2.1 The Opening Balance

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 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 OSAC Regulation.

The return allowance is intended to represent a minimum 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/en/rates/bond-look.html> or on the Department's Oil Sands website (navigating through the "Royalties and Ongoing Projects" 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(2), 15(3) and 15(6)

For pre-payout Projects, the return allowance is an allowed cost. It is calculated monthly by multiplying the net cumulative balance at the end of the month (the difference between the Project's cumulative costs less cumulative revenues) by the return allowance rate for the month. The 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 Statements (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 "Our Business," then 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 did not incur 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 applied over 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 “Our Business,” then 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.

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 may be:

- 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 the Schedules appended to the OSAC Regulation.

Fundamental costs are costs incurred directly to obtain, process, transport or market oil sands products; to reclaim or abandon Project lands; or 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.

Specific Cost Rules

Specific cost rules may be developed for particular types of assets or activities. These rules will be incorporated in the OSAC Regulation or in the Oil Sands Royalty guidelines.

4.2.3.1.1 Reasonable Costs

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.

Cost Allocations

Where an asset or individual is dedicated partially to a Project, a portion of their costs may be allocated to the Project in accordance with the Minister's approval, as long as those costs would be allowed costs under the OSAC Regulation. As with all costs, allocated costs will be subject to audit by the Department, and must be supportable by accounting records. For example, in the case of an employee, part of whose time is devoted to the OSR Project, there should be actual evidence that the employee was paid, and evidence from records (e.g. timesheets) acceptable to the Minister, that a portion of the employee's time was spent on the OSR Project.

Cost Incurred

Costs are considered to be incurred:

- in the month in which the cost is payable, to the extent of the amount that is paid within 90 days, or when the cost is paid to the extent of the amount 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 invoice is provided, and
- provided there are records of them being incurred, or other records from which it could be demonstrated that the cost was incurred.
- an allowed cost, which meets the above criteria, is incurred even if it is not reported by the OSR Project operator.

4.2.3.1.2 Example of an Allowed Cost Determination

Allowed costs are costs that meet the requirements of the OSAC Regulation, and are not specifically excluded by that Regulation. A list of specifically “included” and “excluded” costs is provided in the Schedule of the OSAC Regulation. If there is uncertainty regarding whether a cost is allowable, the Project operator should contact the Department.

All costs claimed are subject to an audit by the Department.

The following example shows the process the Department follows in determining if a cost is an allowed cost.

4.2.3.1.3 Example: Road Costs

The Department determines whether or not road costs are allowable by reference to the specific included allowed cost list in the OSAC Regulation:

- are the costs reasonable and incurred by or on behalf of the Project owners?
- are the road costs found in the specifically included costs list?
- are the costs fundamental costs of the Project?

The Department’s position is that roads located on Project lands and connecting Project facilities are fundamental costs of the OSR Project. The Department recognizes that some road access to Project lands is necessary for the recovery of oil sands, so that “off-project” access road costs may be discretionary allowed costs of an OSR Project.

- Project descriptions must identify access roads that would be used for Project purposes.

4.2.4 Project Revenues

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

- the types of oil sands products that are produced
- the unit price calculations (which determine the value of those oil sands products)
- the 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

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

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 RCP included in the calculation of its Project revenue.

$$\text{Gross Revenue} = \text{Project Revenue} - \text{Cost of Diluent}$$

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 considerations 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 the Project's development area) or technology of the Project.

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

$$\text{Net Revenue} = \text{Project Revenue} - (\text{Allowed Costs} - \text{Other Net Proceeds})$$

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 are included in the calculation of the cumulative balance through their reduction of allowed costs.

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 OSRR'09
- proceeds from the processing of non-project substances in Project facilities
- revenues from the sale, license or lease of Project technology, if that technology's development was an allowed cost of the Project

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, its 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 RCP.

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

ADDING DILUENT AFTER THE "RCP" BUT BEFORE DISPOSITION

Because arms-length dispositions of an oil sands product are used to value that oil sands product at the RCP it is important that the product at the point of disposition and the product at the RCP are qualitatively the same.

In some cases a Project may ship (unblended) cleaned crude bitumen or "partially" blended bitumen from its RCP, to which additional diluent is subsequently added before its disposition.

In this case, the product at the RCP and the product disposed of are not qualitatively similar, and it is not appropriate to value the RCP product at the disposition value: i.e. it would not be correct to value partly blended bitumen at the RCP according to the value of blended bitumen disposed of.

In this situation, where additional diluent is added to the oil sands product after the RCP and prior to disposition, the additional diluent should be deemed to have been added at the RCP. In this way, the product valued at the RCP is qualitatively the same as the product disposed of.

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

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 (FMV) of cleaned crude bitumen that could be obtained from that raw crude bitumen. In determining the unit price, the handling charges will include charges that the Minister is of the

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 themselves.

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

If the percentage of third party dispositions (TPD) of an oil sands product in a Period, as a proportion of the volume of that product delivered to the RCP in the Period, equals or exceeds the third party disposition threshold (TPDT), the proceeds from those TPD can be used to value the entire volume of that product at the RCP. The TPDT, now set at 40%, is prescribed by the Department in its monthly Information Letter. From the Department's website (<http://www.energy.alberta.ca/>), navigate to "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

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

$$\text{Unit Price} = \frac{\text{Total Consideration} - \text{Handling Charges}}{\text{Total Dispositions}}$$

Total Consideration (TC) includes the value of all money and services received or receivable for the TPD in the Period.

Handling Charges (HC) includes all charges incurred in moving the TPD quantities of the oil sands product from the RCP 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 TPD during the Period.

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

If the quantity of an oil sands product disposed of in third party dispositions is less than the TPDT (40%) in a Period, calculated as above, the proceeds of those TPD 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 Period is used to value an equal volume of that oil sands product at the RCP in that Period. The remaining volumes of that product at the RCP must be assigned a FMV for royalty calculation purposes. If a Project has no TPD of an oil sands product in a Period, that product must be entirely valued at the RCP by the assigned FMV for that Period.

Where the TPD do not meet the TPDT, the unit price for an oil sands product for a Period is calculated as follows:

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

Where “TC” and “HC” are the total considerations and handling charges related to TPD, 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 RCP in the Period

“NQ” is “PQ” minus “TD” where “TD” is the volume of TPD, 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 calculated by subtracting from the total volume of blended bitumen delivered at the RCP in the Period the volume of blended bitumen disposed of in third party transactions in that 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 from the total volume of blended bitumen delivered at the RCP in the Period the volume of blended bitumen disposed of in third party transactions in that Period. If the oil sands product is not blended bitumen “CD” is zero.

“P” is the price assigned as the FMV to the volumes of the oil sands product not valued by the TPD, 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 FMV is the Hardisty Bitumen Price for the Project minus the Transportation Allowance (TA) for the Project, both calculated in accordance with the *Bitumen Valuation Methodology (Ministerial) Regulation* (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 TA for the Project, both calculated in accordance with the BVMR.

In the case of any other oil sands product, the price is the FMV 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 FMV must be determined because insufficient volumes (or none) are disposed of in third party transactions.

The BVMR uses a two stage approach to calculating the FMV 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 TA designed to reflect the cost of transporting cleaned crude bitumen from the Project to Hardisty.

By subtracting the TA from the Hardisty Bitumen Price, we arrive at the value of cleaned crude bitumen at the Project's RCP.

NOTE:

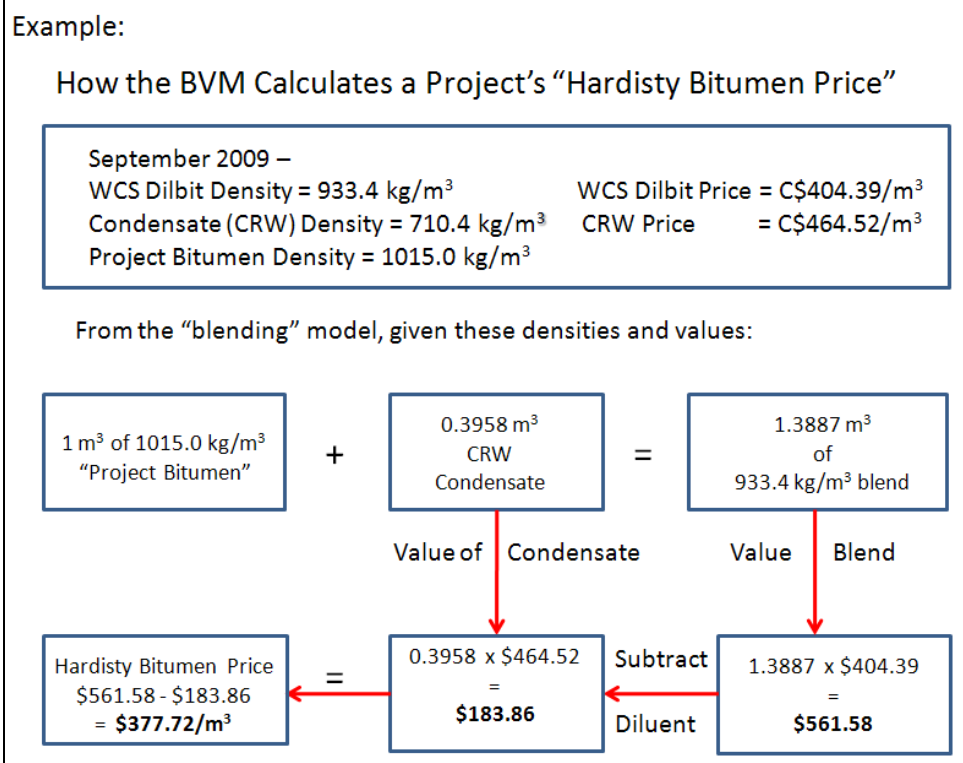
Because the TA is used in the calculation of the value of cleaned crude bitumen at the Project's RCP, no "handling charges" are included in the BVM calculation.

4.2.5.3.1 Hardisty Bitumen Value

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 m³ of Project bitumen at Hardisty.



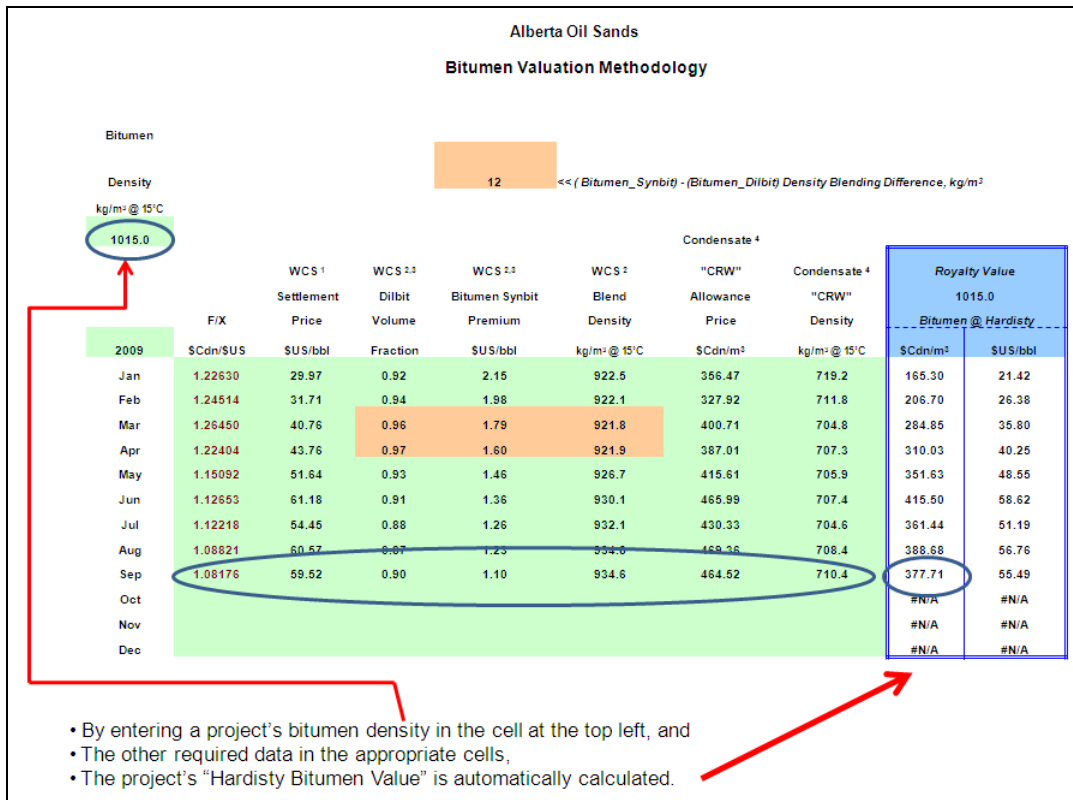
To do these calculations each month, a number of data inputs are needed:

- 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 "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

To make the calculation easier a [BVM model](#) is available on the Department's website (From the Department's website (<http://www.energy.alberta.ca/>), navigate to "Our Business", then to "Oil Sands", "[Royalties and Ongoing Projects](#)", and then "[Bitumen Valuation Methodology \(BVM\) Components](#)") or from the Canadian Association of Petroleum Producers (CAPP) website.



Bitumen Valuation Methodology Model:

This model will calculate the Hardisty Bitumen Price for a Project's bitumen if the data from the Information Letter and the Project's bitumen density is entered in the model's spreadsheet.

Floor Price:

For royalty calculation purposes, a Project's Hardisty Bitumen Price for a month is the greater of the value calculated by the model described above and the "Floor Price" for the month

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, in Canadian dollars, 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.

4.2.5.3.2 Calculating the Transportation Allowance for a Project's Bitumen

The TA 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. Where a Project has more than one removal pipeline, it is the least cost line that is used in the calculation of the TA 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 RCP, or is connected by pipeline to somewhere other than Edmonton or Hardisty) the Minister will prescribe an appropriate TA. 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 TA for a Project is calculated to take into account both:

- the cost of transporting from the Project to Edmonton / Hardisty the volume of dilbit that would result from blending the volume of clean crude bitumen delivered at the Project's RCP 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 TA.

The volumes of dilbit and CRW diluent to be used in calculation of a Project's TA 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/m³) 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 m³ of CRW condensate was required to blend 1.0 m³ 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 m³ of dilbit equal in density to the BVM dilbit. This volume is called the “BVM blend volume” for the Project.

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

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

Here, NQ is the volume of clean crude bitumen delivered at the RCP which must be valued by the BVM. If a Project needed to value 10,000 m³ of bitumen using the BVM, its TA in this example would be based on the cost of transporting:

- $1.3887 \times 10,000 \text{ m}^3 = 13,3887 \text{ m}^3$ dilbit to Edmonton / Hardisty, and
- $0.3958 \times 10,000 \text{ m}^3 = 3,958 \text{ m}^3$ 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.

4.2.5.3.3 Examples of Transportation Rate Calculations for Removal and Diluent Pipelines

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

In each case, unless otherwise noted, we will assume the same bitumen volume at RCP (10,000 m³), calculated blend volume (13,887 m³), and calculated diluent volume (3,958 m³) 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 OSAC Regulation where the service is obtained on a NAL basis.

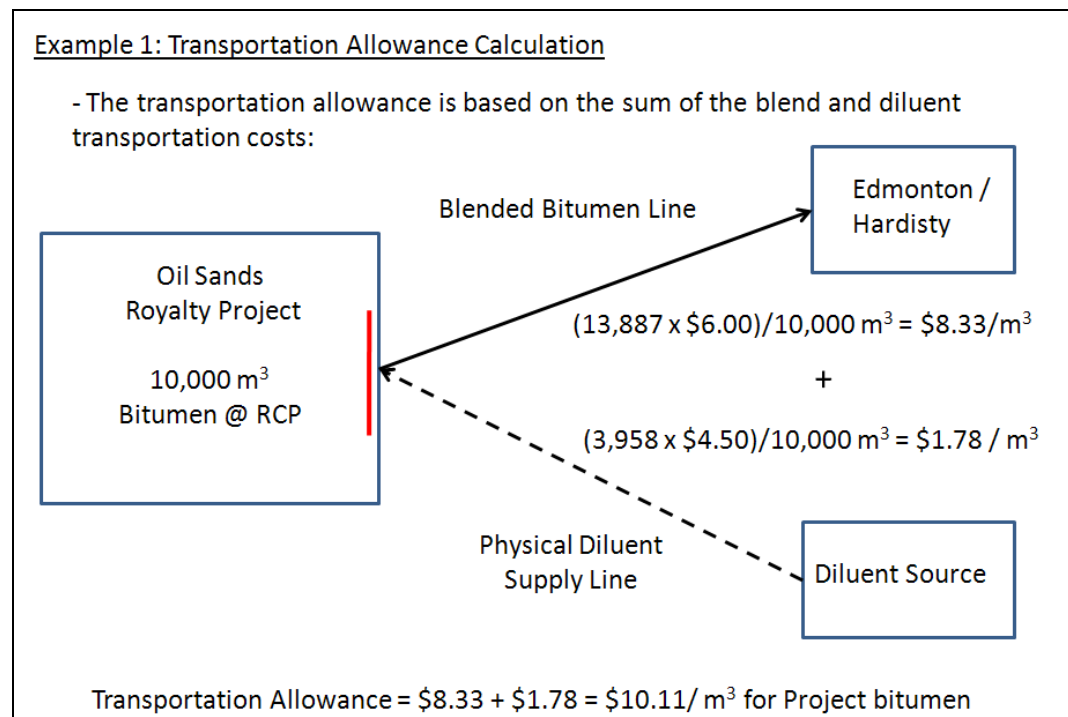
Example 1: A Project with a Dilbit Removal Pipeline and an Actual Diluent Supply Line

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

Assuming a tariff on the dilbit removal line of \$6.00/m³ and a tariff on the diluent line of \$4.50/m³, the TA for the Project would be:

$$[(13,887 \times \$6.00) + (3,958 \times \$4.50)] / 10,000 = \$10.11/\text{m}^3 \text{ of Project bitumen}$$

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 RCP.



Example 2: A Project with a Dilbit (Blend) 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.

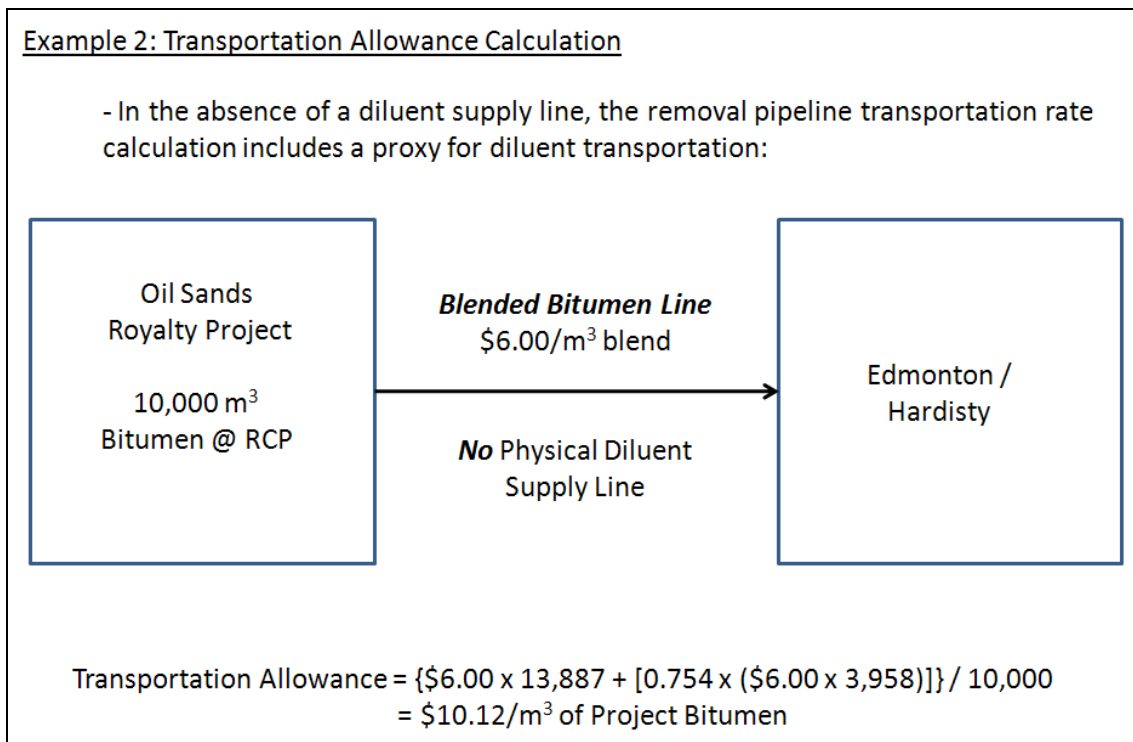
In this case sections 5(3) and 5(4) of the BVMR would apply and the removal pipeline transportation rate calculation would include an allowance for diluent delivery to the Project.

Assuming again a blend tariff of \$6.00/m³, the TA would be calculated as;

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

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 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.

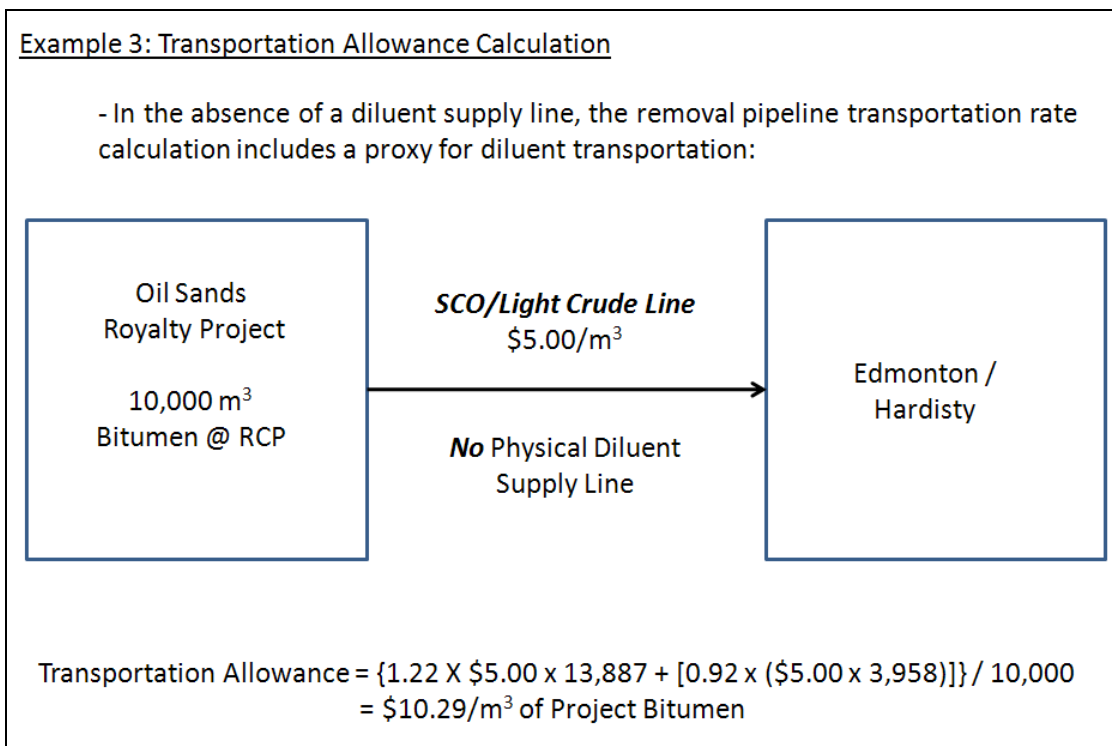
In this case section 5(6) and 5(7) of the regulation would apply and the removal pipeline transportation rate calculation would again include an allowance for diluent delivery to the Project.

Assuming a \$5.00/m³ SCO tariff, the transportation allowance would be calculated as:

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

In this expression:

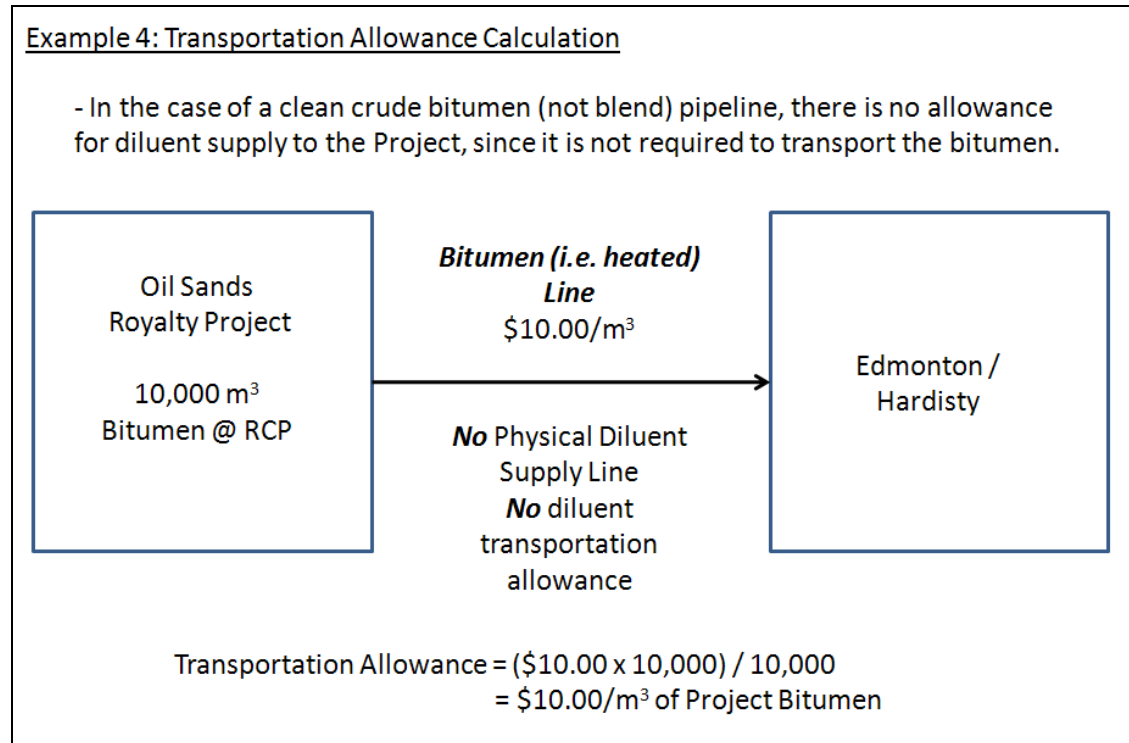
- the term (13,887 x \$5.00 x 1.22) represents “TRC” from the Regulation – the cost of transporting the blend volume at the SCO tariff, with that tariff increased by the factor of 1.22 to represent a blend transportation cost as per section 5(7)
- the term (3,958 x \$5.00) represents “DRC” from the Regulation – 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



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.

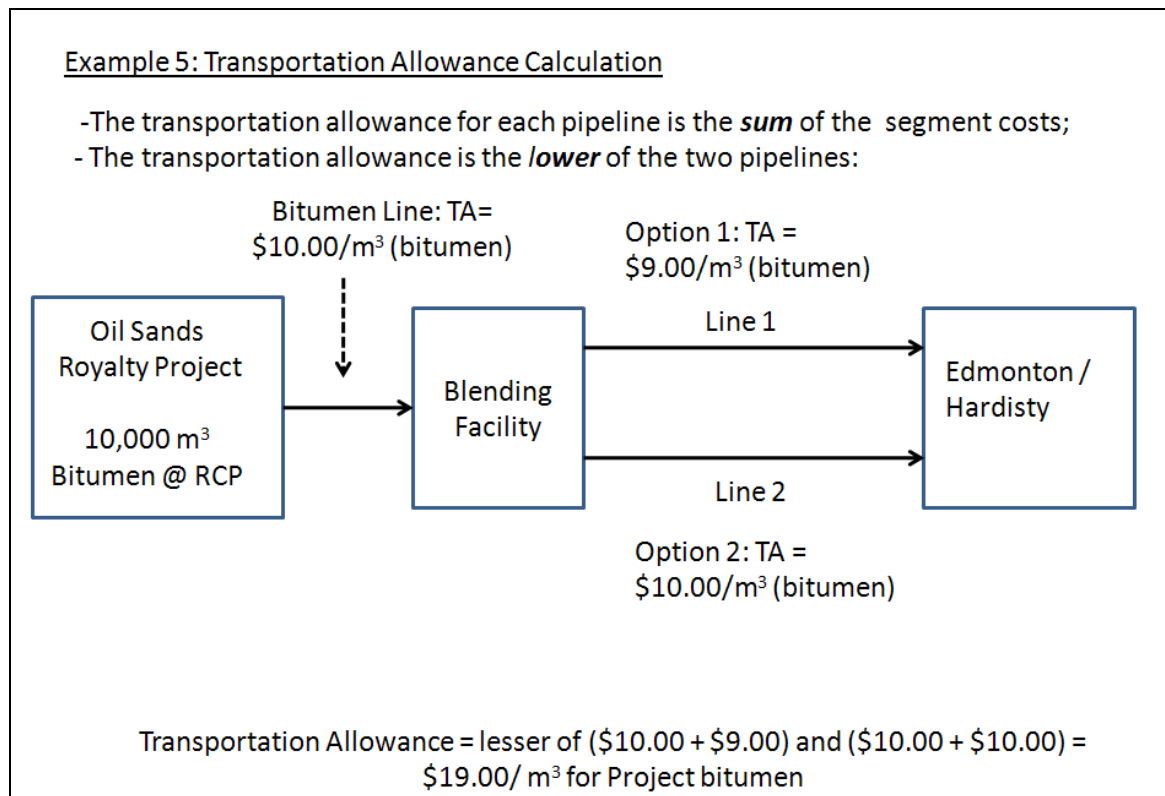
In this case the TA is simply the cost of transporting the bitumen divided by the volume of bitumen. Since this form of transportation does not require diluent, no allowance for diluent transportation costs is included.



Example 5: A Project with Multiple Pipeline Segments / Options

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 TA 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 TA.



Summary

For a Project requiring BVM the FMV for its bitumen is the Hardisty Bitumen price for the Project minus the TA for the Project, calculated as described above. This FMV is the “P” in the unit price formula described in section [4.2.5.2 “Third Party Dispositions Do Not Meet the Third Party Disposition Threshold”](#).

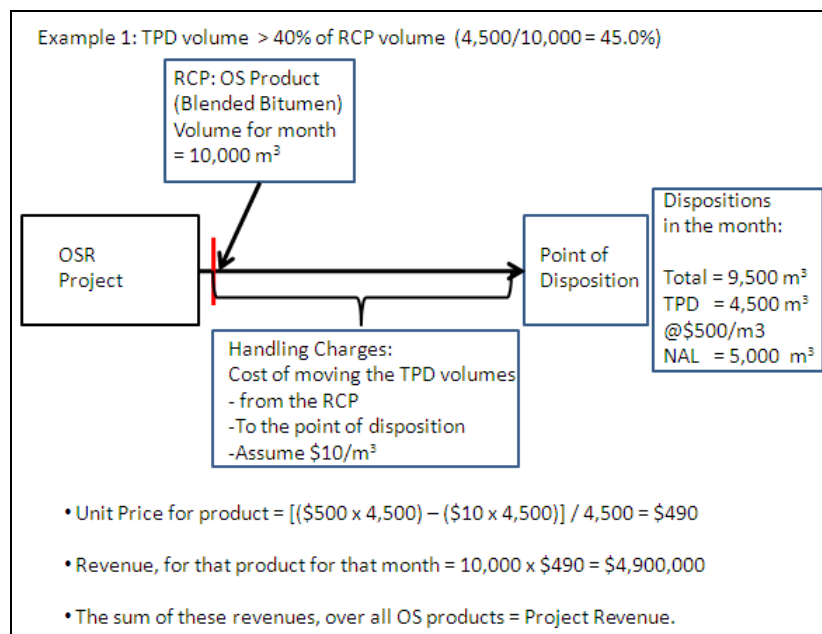
4.2.5.4 Examples of Oil Sands Unit Price and Project Revenue Calculations

Key Points:

- the price obtained for dispositions in a month is used to value production (RCP) 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 (RCP) volumes in that month.
- it is the ratio of TPD volumes to production (RCP) volumes that is compared to the TPDT when valuing royalty volumes.

Example 1: Third Party Dispositions > 40% of Production (RCP) Volumes:

In this case the TPD can be used to value all production RCP volumes for royalty calculation purposes.



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

In calculating the handling costs for the TPD 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 TPD volumes
- if a single charge is levied to transport all the disposed volumes (9500 m³ in this example) the TPD handling costs can be calculated as:
 - Total HC x (TPD / Total dispositions)

If the handling costs are incurred as NAL costs (i.e. on an affiliated non-project pipeline) the per unit cost of service should be applied to each TPD unit.

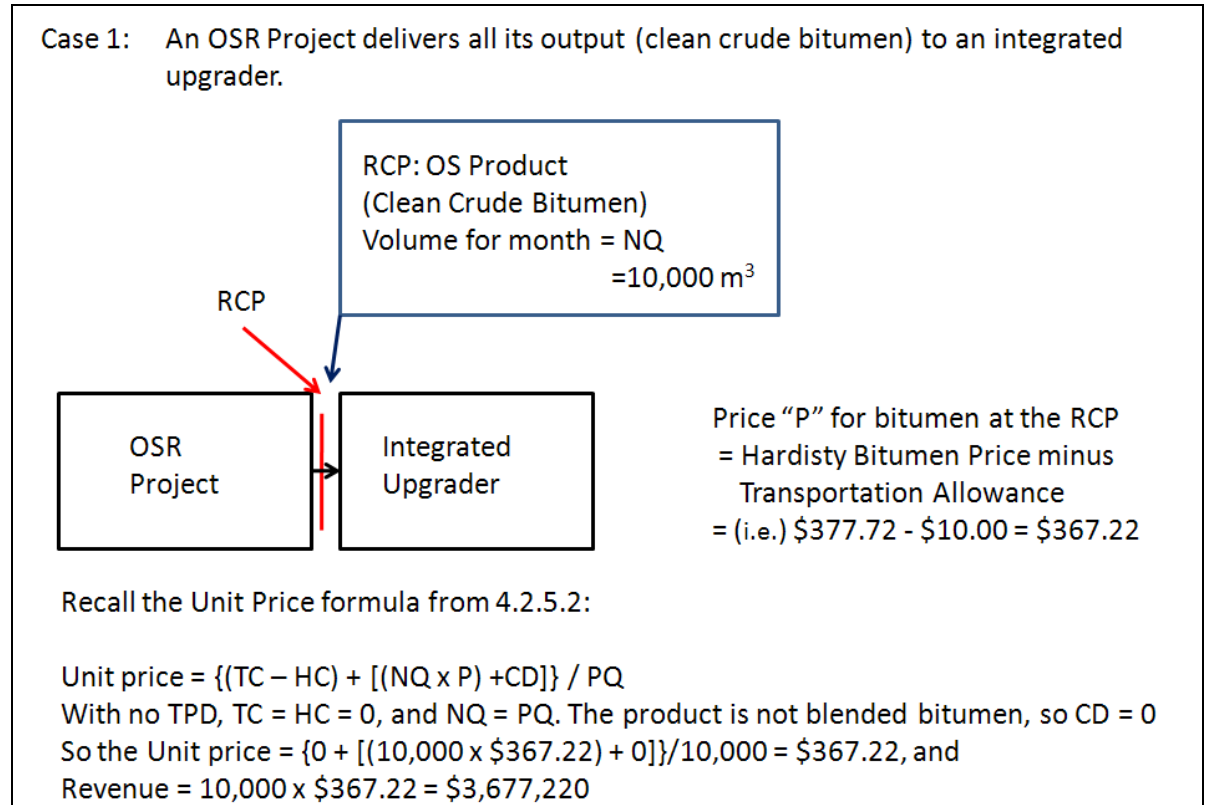
Example 2: No Third Party Dispositions (Non-Arm's Length Transactions)

In case 1, where an OSR Project delivers all its output to an integrated upgrader, a FMV must be prescribed as the unit price of the oil sands product at the RCP. Where the oil sands product is cleaned crude bitumen or blended bitumen the BVMR is used in determining this FMV 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 RCP according to the BVMR. The value of the diluent actually included in the Project's blended bitumen at the RCP is then "added in" in calculating the unit price for the Project's blended bitumen. (This is "CD" [in section 4.2.5.2 "Third Party Dispositions Do Not Meet the Third Party Disposition Threshold"](#)).

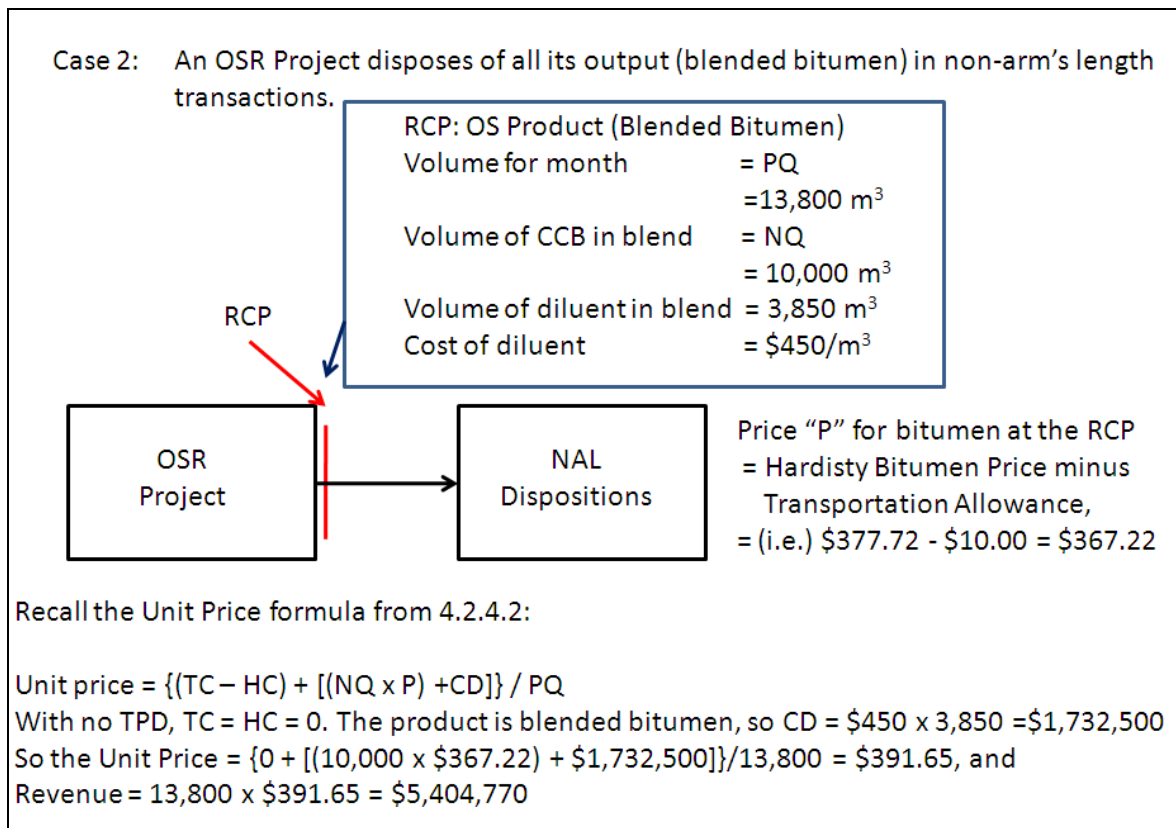
Also, because the BVMR includes a TA component, "actual" handling charges related to the Project's clean crude bitumen or blended bitumen are not included in the unit price calculation.

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 RCP, it is the actual volume and price of diluent (at the RCP) 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 RCP. 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 (RCP) Volumes

In this case, the volume of TDPs is too small to allow those dispositions to value all the volumes of the oil sands product at the RCP. A volume at the RCP equal to the volume of TPDs will be valued according to those dispositions: the remaining volumes at the RCP will need to be valued at “FMV” – 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 RCP volume of 13,800 m³ (= PQ). Assume 4,800 m³ were disposed of in TPDs at a price of \$385/m³, and the cost of transporting those TPD volumes to the point of disposition was \$6/m³. As 4,800m³/13,800m³ = 34.7%, < 40%, these dispositions cannot value all the volumes at the RCP: they will value 4,800 m³ at that point.

Assume that the BVM value of bitumen at the Project (Hardisty Bitumen Price – TA) = \$367.72/m³. If there were 10,000 m³ of clean crude bitumen in the 13,800 m³ of blend at the RCP, we can calculate NQ = the amount of bitumen in the NAL dispositions (9,000 m³ of blend) to be (10,000/13,800) x 9,000 = 6,521.7 m³. By similar reasoning, we can calculate CD, the cost of diluent in the NAL volume as (9,000/13,800) x 3,850 x \$450 = \$1,129,891 – using the diluent volume and value from case 2 again.

Recalling the unit price formula again:

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

Substituting in the values from above:

$$\text{Unit price} = \{((4,800 \times \$385) - (4,800 \times \$6)) + [(6521.7 \times \$367.72) + \$1,129,891]\} / 13,800$$

$$\text{Unit price} = \$387.48/\text{m}^3, \text{ of blended bitumen.}$$

$$\text{Revenue} = \$387.48 \times 13,800 = \$5,347,224.$$

<p>Example 3: An OSR Project's output (blended bitumen) is disposed of in both third party and non-arm's length transactions.</p>															
<table border="1"> <tr> <td colspan="2">RCP: OS Product (Blended Bitumen)</td> </tr> <tr> <td>Volume for month</td> <td>= PQ</td> </tr> <tr> <td></td> <td>= 13,800 m³</td> </tr> <tr> <td>Volume of CCB in blend</td> <td>= NQ</td> </tr> <tr> <td></td> <td>= 10,000 m³</td> </tr> <tr> <td>Volume of diluent in blend</td> <td>= 3,850 m³</td> </tr> <tr> <td>Cost of diluent</td> <td>= \$450/m³</td> </tr> </table>	RCP: OS Product (Blended Bitumen)		Volume for month	= PQ		= 13,800 m ³	Volume of CCB in blend	= NQ		= 10,000 m ³	Volume of diluent in blend	= 3,850 m ³	Cost of diluent	= \$450/m ³	<p>Price “P” for bitumen at the RCP = Hardisty Bitumen Price minus Transportation Allowance, = (i.e.) \$377.72 - \$10.00 = \$367.22</p> <p>Price of blended bitumen in AL transactions = \$385/m³</p>
RCP: OS Product (Blended Bitumen)															
Volume for month	= PQ														
	= 13,800 m ³														
Volume of CCB in blend	= NQ														
	= 10,000 m ³														
Volume of diluent in blend	= 3,850 m ³														
Cost of diluent	= \$450/m ³														
<p>Unit price = $\{(\text{TC} - \text{HC}) + [(\text{NQ} \times \text{P}) + \text{CD}]\} / \text{PQ}$ Here, $(\text{TC} - \text{HC}) = (\\$385 \times 4,800) - (\\$6 \times 4,800) = \\$1,819,200$; $\text{NQ} = (10,000 / 13,800) \times 9,000 = 6,521.7$ $\text{CD} = \\$450 \times 9,000 \times (3,850 / 13,800) = \\$1,129,891$ So the Unit price = $\{ \\$1,819,200 + [(6,521.7 \times \\$367.72) + \\$1,129,891] \} / 13,800 = \\$387.48 / \text{m}^3$ Revenue = $13,800 \times \\$387.48 = \\$5,347,224$</p>															

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 accept 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 OSRR'09 section 4.4 and 4.5, 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)

The Crown's royalty share of an oil sands product from a pre-payout Project is calculated monthly at the rate of gross revenue royalty rate $R_G\%$ of the volumes of the oil sands products delivered at their RCPs in that month.

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

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.

For a pre-payout Project, this royalty compensation must be paid to the Crown not 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.

$R_G\%$ is the pre-payment gross revenue royalty rate. It 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 –

$$\begin{aligned} R_G\% &= 1\%, \text{ when } \$\text{Cdn WTI} \leq \$55, \\ R_G\% &= 1\% + \{(8\%/\$65) \times (\text{WTI} - \$55)\} \text{ when } \$55 < \text{WTI} < \$120 \\ R_G\% &= 9\%, \text{ when } \$\text{Cdn WTI} \geq \$120 \end{aligned}$$

The Department publishes the pre-payout gross royalty rate $R_G\%$ 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 "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

The royalty payable to the Crown on 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 zero, the royalty payable on that product is zero, not a negative amount.

Example 1:

Let \$Cdn WTI = \$55, so $R_G\% = 1\%$; if a Project delivered 100 units of clean crude bitumen to its RCP in a month, with a unit price of \$50, then the Crown's royalty share would be $1\% \times 100 = 1$ unit of clean crude bitumen, and the royalty compensation due would be $1 \text{ unit} \times \$50 = \50 .

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 1a:

Let $R_G\% = 1\%$. 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 RCP 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 $1\% \times 100 = 1.0$ 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 \text{ units} \times \$50) - (0.5 \times \$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 $1\% \times 100 = 1.0$ unit,
- the amount of blended bitumen containing that share is 1.5 units,
- the value of that blended bitumen is $1.5 \times \$20 = \30.00 ,
- the cost of diluent in that amount of blended bitumen is $0.5 \times \$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 OSAC Regulation, 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 zero, and
- the value of the blended bitumen (if any) containing the Crown's share of clean crude bitumen is greater than the cost of the diluent in that volume of blended bitumen.

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

$$R_G\% \times \text{Gross Revenue}$$

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 the greater of the gross royalty rate ($R_G\%$) for the Period and the net royalty rate ($R_N\%$) for the Period.

As with pre-payout Projects, the gross royalty rate can vary from 1% to 9% depending on the 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 for a Project for a Period is the product of the net royalty percentage multiplied by the ratio of the Project's net revenue (NR) to its gross revenue (GR) for the Period. The net royalty percentage 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:

$$R_N\% = 25\% \times (NR/GR), \text{ when } \$\text{Cdn WTI} \leq \$55$$

$$R_N\% = \{25\% + [(15\%/\$65) \times (WTI - \$55)]\} \times (NR/GR), \text{ when } \$55 < \text{WTI} < \$120$$

$$R_N\% = 40\% \times (NR/GR), \text{ when } \$\text{Cdn WTI} \geq \$120$$

Example 1:

Assume a post-payout Project delivers 10,000 units of an oil sands project to its RCP in a Period. Let the average WTI price for the Period be \$75, so $R_G\%$ for the Period is 3.46154%, and the net royalty percentage 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 $R_N\% = 29.61538\% \times (\$200,000/\$1,000,000) = 5.92308\%$.

As $R_N\% = 5.92308\%$ is greater than $R_G\% = 3.36154\%$, 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 RCP, royalty compensation is triggered.

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 zero, 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 ($R_G\%$) and the net royalty percentage ($R_N\%$) for a Period at the end of each Period, in its Information Letter for December. Example of the Information Letter:

Government of Alberta ■			
Energy			
Oil Sands Monthly Royalty Rates			
August 2011			
Royalty Data			
Pre-Payout Gross Royalty:		6.00554%	(based on Prod Month actual WTI Price)
Post-Payout Gross Royalty:		5.53415%	(based on the average WTI price for Prod Year)
Post-Payout Net Royalty % Factor:		33.50154%	(based on the average WTI price for Prod Year)
WTI Prices and Exchange Rates			
Month		WTI Price USD\$	Exchange Rate
Jan 2011	Act	\$89.23	1.00619312
Feb 2011	Act	\$89.58	1.01260183
Mar 2011	Act	\$89.74	1.02396980
Apr 2011	Act	\$102.98	1.04360712
May 2011	Act	\$110.04	1.03308326
Jun 2011	Act	\$101.36	1.02380343
Jul 2011	Act	\$96.29	1.04679158
Aug 2011	Act	\$97.34	1.01746337
Sep 2011	Est	\$86.34	1.02530000
Oct 2011	Est	\$88.81	1.02530000
			= \$95.67 (CAD\$)

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 zero, and
- the value of the blended bitumen (if any) containing the Crown's share of clean crude bitumen is greater than the cost of the diluent in that volume of blended bitumen, then:

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

$$R_G\% \times \text{Gross Revenue, and} \\ R_N\% \times \text{Net Revenue}$$

Where Gross Revenue = Project Revenue – Cost of Diluent, and
Net Revenue = Project Revenue – (Allowed Costs – Other Net Proceeds)

4.4.1 Installments

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 ($R_{Gest}\%$) and estimated annual net royalty percentage, which are to be used in calculating these installments.

The installment due in each month is the **greater of**:

1. $R_{Gest}\%$ x Gross Revenue for that month and all preceding months in the Period, and
2. Estimated annual net royalty % 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.

Minus

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 ($R_{Nest}\%$), the installment due in respect of a particular month is the greater of $R_{Gest}\%$ and $R_{Nest}\%$ 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 $R_{Gest}\% = 3.36154\%$ and estimated annual net royalty percentage of 29.61538%.

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

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

For the Project examples in this chapter, as for all OSR Projects, Project **sales** are sales of all oil sands products obtained from oil sands rights approved as part of the Project description.

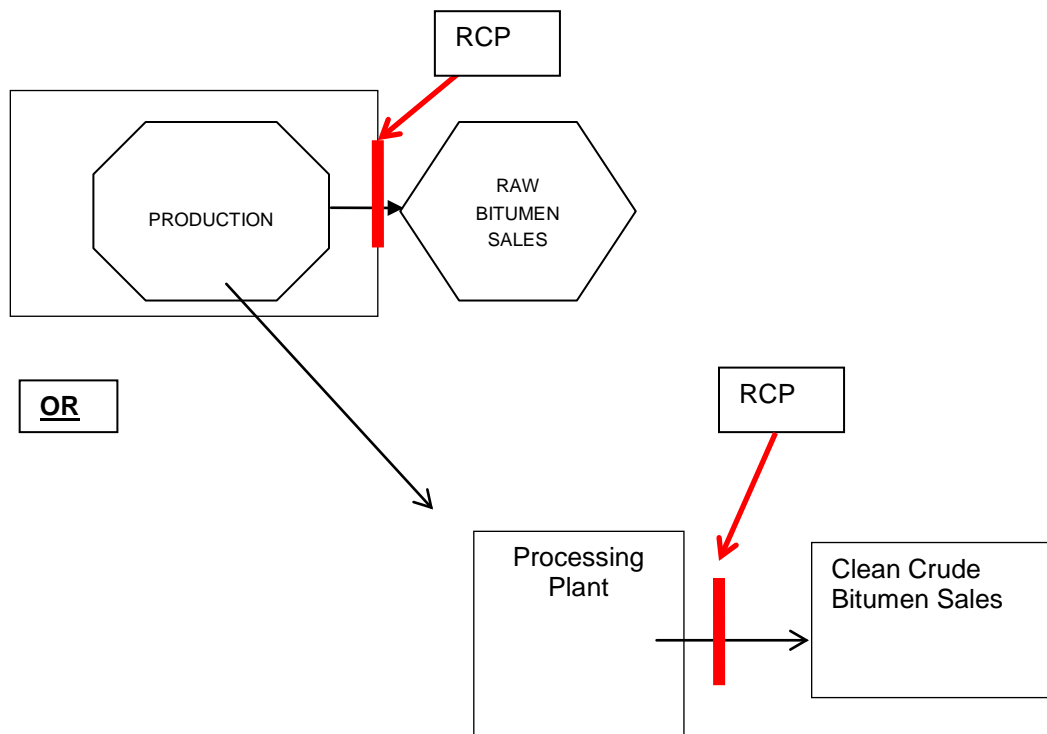
The revenue calculated as the royalty volume of a product multiplied by the unit price (sales less handling charges) for that product is called the product revenue. The sum of product revenues is the **Project revenue**.

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

If raw bitumen is disposed of before being processed to cleaned crude bitumen, the RCP is where the bitumen is removed from Project lands.

If, before being disposed of, the raw bitumen is processed in a plant which is not part of the Project, the RCP for the Project is deemed to be the outlet of the processing plant.

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 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 FMV 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 RCP. 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.

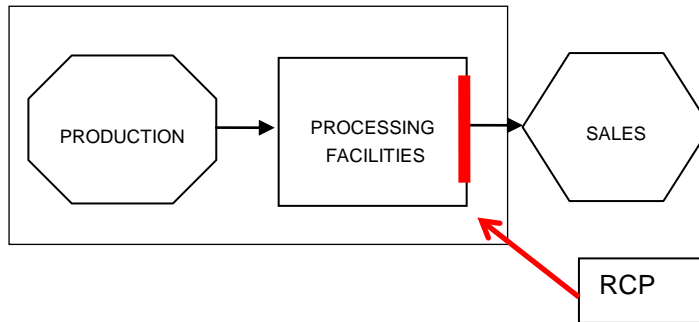
If, before being disposed of, the raw bitumen is processed in a plant which is not part of the Project the costs of transporting the raw bitumen to the plant and processing the raw bitumen are allowed costs of the Project. Non-project processing plants provide a basic service to the Project.

Allowed Costs versus Handling Charge Deductions:

For all Project configurations, handling charges are those charges incurred between the RCP 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 RCP. 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

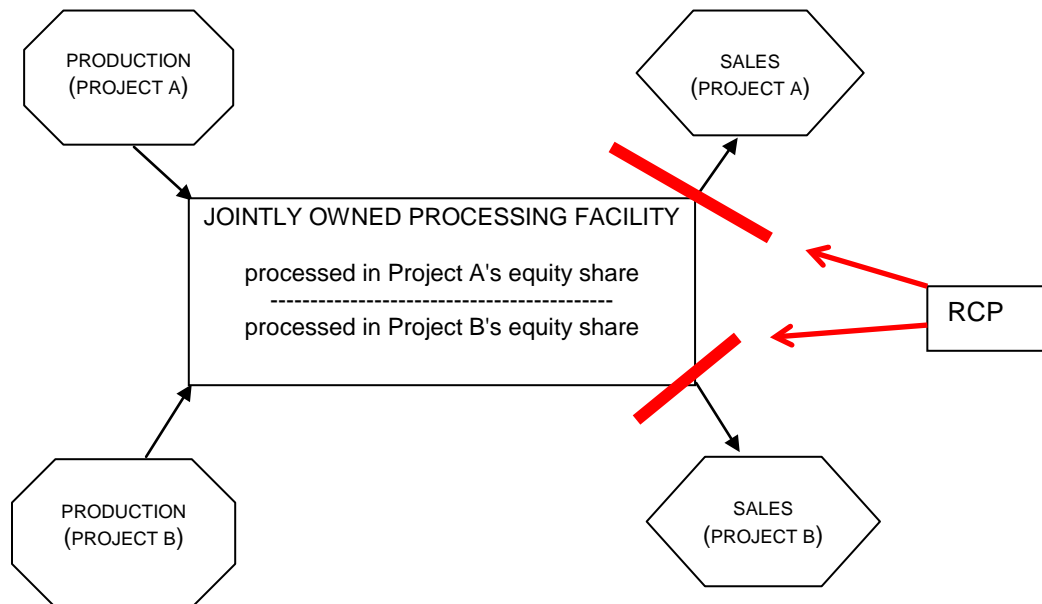
The RCP is at the outlet of the processing plant, and royalty is calculated on the volume of cleaned crude bitumen at that point.

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.

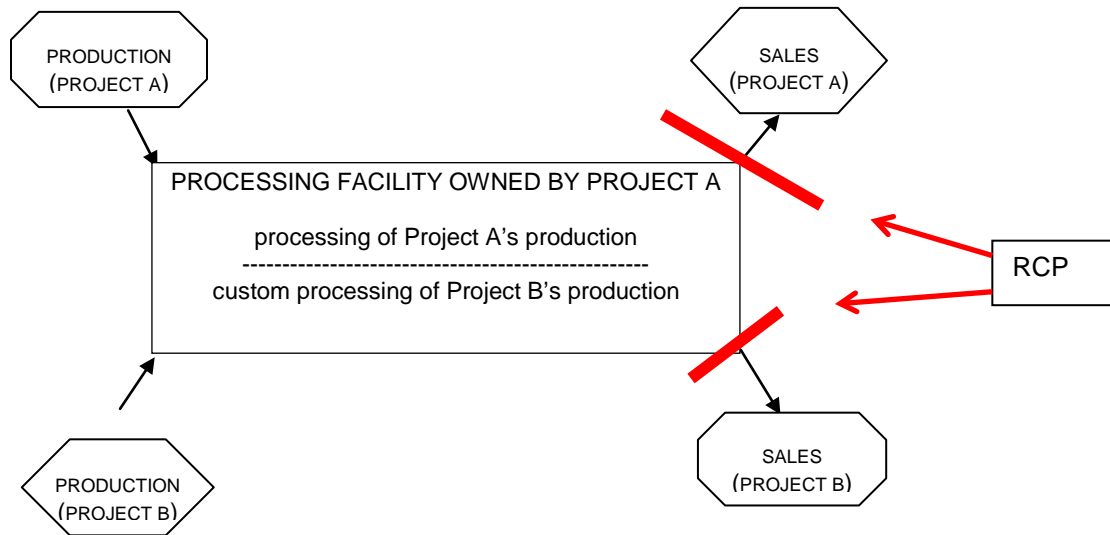
Allowed Costs

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 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

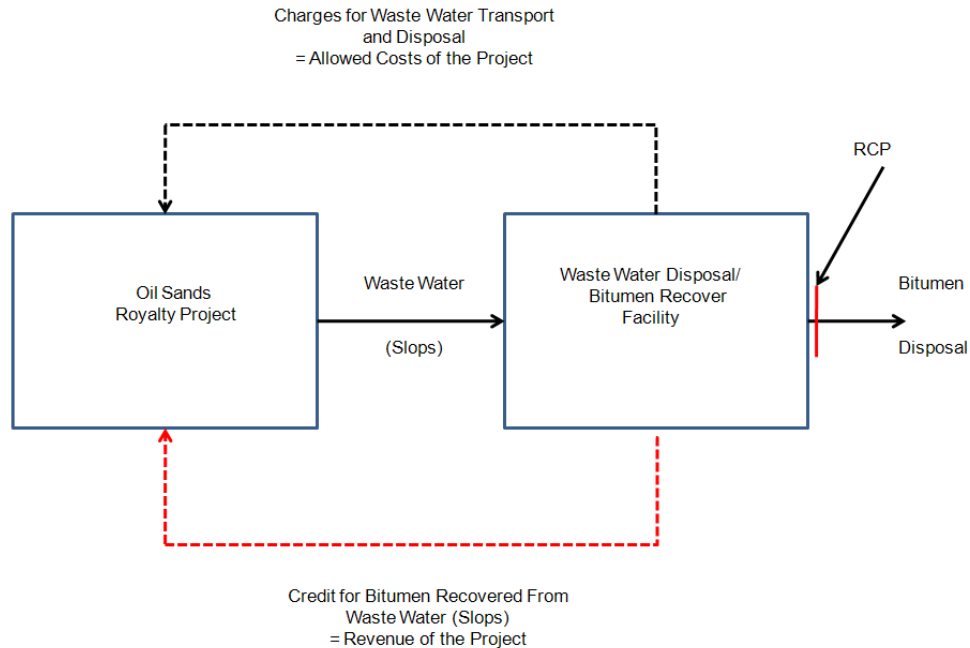
Each Project can deduct allowed costs attributed to production of its raw bitumen.

- 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

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 RCP 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 RCP).
- The credit received for the recovered bitumen from the slops would be ONP for the Project.

5. Capital Assets and OSR Projects

5.1 Capital Assets

Assets are considered capital assets 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 Included in OSR Projects

Oil Sands Royalty Regulation 2009, Section 14

Capital Assets 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 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 OSAC Regulation, is not a core or supporting asset and cannot be included in a project description.
- A core or supporting asset must meet the OSR Project use threshold defined in the OSRR'09 (75%) 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 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

Generally, a (core or supporting) capital asset must either be entirely included in a Project description, or entirely excluded. There are however certain capital assets, as specified in the OSRR'09, 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.
- 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.

Where a core or supporting asset is partially 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, in the proportion to which the asset was included in the project description.

5.1.1.3 Costs of Capital Assets in OSR Projects

Where a core or supporting asset 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 OSRR'09.

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 OSAC Regulation must be applied to value the transactions.

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

5.1.1.4 Revenues from Capital Assets in OSR Projects

Capital assets 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).

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 OSRR’09, and are discussed in Chapter 6 of these Guidelines.

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

5.1.2 Summary Table: Treatment of Costs and Revenues

Treatment of Costs and Revenues of Capital Assets Included in Royalty Projects		
Capital Assets 100% Included	Costs	Revenue
<p>Capital asset included completely in the Project description.</p> <ul style="list-style-type: none"> • must be a core or supporting asset – s.14(2) • use of the asset must be \geq threshold use (75%) – s.14(2)(a) 	<p>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.)</p> <ul style="list-style-type: none"> • subject to OSAC, s.3 	<p>Any revenues attributable to non-project use of the asset, or its disposition, are “other net proceeds” of the Project.</p> <ul style="list-style-type: none"> • s.23(2)(h)(i)(j)(k)
Capital Assets Partly Included	Costs	Revenue
<p>NB: Capital Assets (other than the exceptions noted below) may NOT be partially included in the Project description.</p> <ul style="list-style-type: none"> • s.14(4) <p>Exceptions: (at the Minister’s discretion)</p> <ul style="list-style-type: none"> • 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 – s.14(8)&(9). • A proportion of a Diluent Recovery Unit (DRU), equal to the proportion of the processing plant included – s.14(10) • Cross-Boundary wells - s. 14(11) 	<p>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.</p> <p>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.</p> <p>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.</p>	<p>Any revenues attributable to non-project use, or disposition, of the partly included asset are “other net proceeds” of the Project.</p> <p>Examples:</p> <ul style="list-style-type: none"> • Revenue from processing oil sands products not owned by the lessees in that proportion of the processing plant included in the Project description 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 – s.23(2)(d)(ii)

5.2 Solution Gas and Off-Lease Fuel Gas

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 12(2)(b)(ii)

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 OSRR'09. 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 OSRR'09. 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*.

Until January 1, 2011, the business rules respecting the allocation of solution gas conservation costs between the OSR Project and non-project uses (i.e. gas cost allowance (GCA)) are subject to approval by Crown audit.

Effective January 1, 2011, the Oil Sands business rules regarding solution gas conservation costs will be as 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 transferred to GCA.
 - a) Where the ERCB 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 ERCB 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 Descriptions 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 13 of the *Natural Gas Royalty Regulation, 2009*.
 - 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, 2009*.
 - i. The applicability of the royalty exemption to minor, isolated exports of solution gas will be dealt with by Gas Royalty.
 - ii. Measurements and reporting of solution gas exports will be dealt with between the Project operator, the Petroleum Registry of Alberta and Gas Royalty.
 - iii. Valuation for gas royalty purposes of solution gas exports will be dealt with under the *Natural Gas Royalty Regulation, 2009*.
 - iv. The royalty treatment of other gas substances like sulphur recovered from solution gas will be dealt with by Gas Royalty.
 - v. 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.
 - i. The only criteria for the inclusion of a solution gas asset in an OSR Project will be as set out in 1 and 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 Regulation, 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 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 Services

The calculation of costs for non-basic pipelines depends on whether or not a fair market value (FMV) can be established for the use of the pipeline:

- If the pipeline is owned by the OSR Project owner or by an affiliate, but the Minister can establish FMV for the pipeline service, the allowed cost is the lesser of the amount charged to the Project or FMV.
- If the Minister cannot establish a FMV, the allowed cost is the lesser of the amount charged to the project or the actual cost incurred, as determined by a cost-of-service calculation.

5.3.1.1 Allowed Cost 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.
- 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 rules apply:

- 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.

5.3.1.2 Allowed Costs Based on Cost-of-Service Calculations

In the case of a non-basic pipeline providing transportation of oil sands products from a Project, if a FMV cannot be 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; or
- (b) the cost of service (COS).

The COS calculation methodology is described below:

- The COS calculation is based on a Project's owner's capital investment in the pipeline and its share of the pipeline's operating costs. The Project's owner's share of operating costs is determined by its proportion of throughput during the year.
 - For capital costs, each Project owner calculates the per barrel capital charge for his project based on his portion of the pipeline's capital cost. For details, see Example 1 in this section.
- The pipeline's allowed capital costs are depreciated on a 5% straight-line basis over its useful life. For royalty calculation purposes the useful life of a pipeline is estimated to be at least 20 years.

- There is no floor on the undepreciated capital balance used to determine the return on capital. That is, the asset is depreciated until the remaining undepreciated balance is zero.
- The following formula is used to calculate the allowed rate of return on capital (RORC).

$$\text{RORC} = \left(\text{Deemed Debt Percentage} \right) \left(\text{Deemed Cost of Debt} \right) + \left(\text{Deemed Equity Percentage} \right) \frac{\text{Deemed Cost of Equity}}{(1 - \text{Deemed Corporate Income Tax Rate})}$$

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).

In 2009, the NEB indicated that it would no longer be utilizing the multi-pipeline cost of capital rate in its procedures. It continued to publish the rates for 2010 (in late 2009) and 2011 (in late 2012).

For 2012 and subsequent years, use the LTBR +3% for the deemed cost of equity.”

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.

Additional cost rules apply to:

- pipeline overcapacity (see section 5.3.3 "Cost Rules for Pipeline Overcapacity")
- capital additions to pipelines (see section 5.3.4 "Cost Rules for Capital Additions to Non-Basic Pipelines")

Example 1

Assumptions:

- The pipeline is in its 5th year of operations.
- Total 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)

Calculation:

- Owners capital cost is
(50% of \$90 million) = \$45 million;
- Depreciation charge is
(\$45 million / 20 years) = \$2.25/year;
- Undepreciated capital in year 5 is
\$45 million - (2.25 million * 5 years) =
\$33.75 million;
- The per barrel capital charge would be equal to the capital rate base multiplied by the rate of return, plus the Period depreciation, divided by throughput:

$$\frac{(\$33.75 \text{ million} * 12.92\%) + 2.25 \text{ million}}{27.5 \text{ million barrels}} = \$0.24/\text{barrel} \text{ Capital charge}$$

Additionally, the COS would include the project's share of operating costs, based on throughput (in this case 27.5 / 55 = 50%).

Example 2

When a Project's throughput exceeds the Project's share of the capacity of the pipeline, the cost of the excess throughput is allocated to the Project according to the actual amount charged by the other pipeline owners. This is because the excess throughput represents an arm's-length transaction.

Assumptions:

- In the previous example, assume that in 5 years, the owner uses 35 million barrels of capacity on the NAL pipeline, rather than the allocated 27.5 million;
- The second owner's actual amount charged is \$1.75 / barrel.

Calculation:

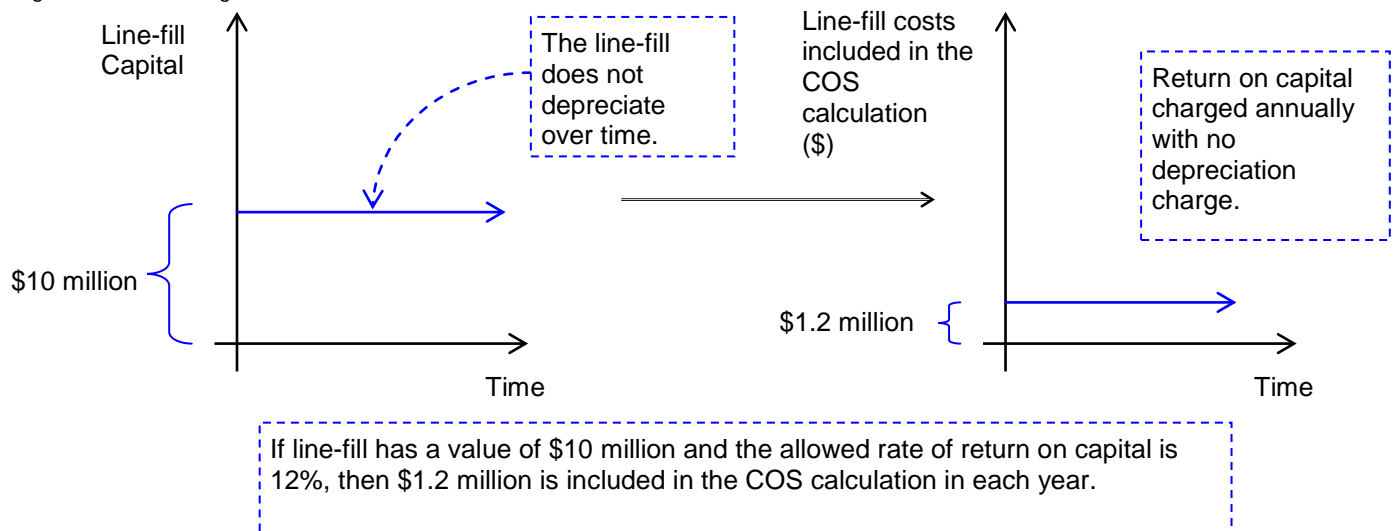
- The first owner's share of throughput, 27.5 million barrels, will be charged a capital charge of \$0.24/barrel, plus operating costs based on the owner's share of throughput;
- The additional (35 million - 27.5 million) = 7.5 million barrels will be charged \$1.75/barrel for a total of \$13.13 million;
- The \$13.13 million will be the pipeline tariff charge for the first project owner, and will be recorded as an Other Net Proceed (ONP) for the second project owner.

5.3.2 Line Fill Costs

In addition to the COS as calculated in section [5.3.1.2 “Allowed Costs Based on Cost-of-Service Calculations”](#), 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 price at which it was acquired. Its return rate (RORC) is the same as the return rate allowed for the cost-of-service calculation. The following cost rules apply:

- Line fill is treated as inventory.
- 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



5.3.3 Cost Rules for Pipeline Overcapacity

Oil sands Project owners may build pipelines that are oversized in relation to the needs of the Project. Overcapacity pipelines operate at lower utilization levels. This reduces the Crown's royalty by creating higher costs and higher unit price deductions for the duration of the oil sands Project.

If an OSR Project owner's share of a non-basic pipeline is subject to a COS calculation, and if that share of the pipeline's annual throughput capacity is less than 150% of the capacity required to transport the annual ERCB-approved bitumen production from the owner's Project, the full annual capital depreciation is charged against the owner's COS, in each year.

If the share of the pipeline's annual throughput capacity is greater than 150% of the capacity required to transport the Project's ERCB-approved annual bitumen production, the following cost rules apply:

1. The OSR Project or pipeline owner chooses what percentage of the pipeline is considered Project related. The chosen percentage must be justified by a business case and approved by the Department.
2. The annual capital depreciation charged against the COS is prorated based on the percentage of the pipeline that is Project related.

$$\text{Annual capital depreciation (\$/year)} = \frac{(\text{Owner's share of undepreciated capital} \times \text{Percentage of the pipeline that is Project related})}{\text{Expected life of the pipeline}}$$

3. The declared Project-related percentage of pipeline use is subject to review by the Department if circumstances change.

For example

Assumptions:

- A NAL non-basic pipeline subject to a COS calculation has capacity of 55 million barrels per year;
- The undepreciated total cost of the pipeline is \$90 million;
- The expected life of the pipeline is 20 years;
- One owner's share is 50%, or 27.5 million barrels per year;
- ERCB approval for the owner is 10 million barrels per year.

Calculation:

- The owner elects and justifies that 50% of its share, or 13.75 million barrels per year, is identified as a "project pipeline".
- The annual capital depreciation charged is 50% of the owner's share of capital (50% of \$90 million = \$45 million), straight-line over 20 years:

$$\frac{\$45 \text{ million} \times 50\%}{20 \text{ years}} = \$1.13 \text{ million/year}$$

5.3.4 Cost Rules for Capital Additions to Non-Basic Pipelines

Two types of capital costs are used in COS calculations for non-basic pipelines:

- capital costs for repairs or maintenance
- capital costs for material and non-material enhancements
 - For a capital cost to be considered material, it must be more than 10% of the original capital cost of the pipeline. It must also extend the life of the pipeline or increase pipeline capacity.

All capital costs for repairs or maintenance are eligible in the year in which the expenditure was incurred.

All capital costs that are not material are eligible in the year in which the expenditure was incurred.

Material capital costs are treated in one of two ways:

- If the cost is less than the pipeline's undepreciated capital pool balance, it is added to the pool balance and depreciated over the remaining life of the pool.
- If the cost is greater than the pipeline's undepreciated capital pool balance, it is added to the pool balance and the whole pool is depreciated over a new 20-year Period—that is, for the pipeline's expected life.

For example

Assumptions:

- A NAL non-basic pipeline subject to a COS calculation had an original total cost of \$90 million;
- The expected life of the pipeline is 20 years;
- In year 15, an additional \$25 million of capital is spent on the pipeline.

$$\frac{\$25 + \$22.5 \text{ million}}{20 \text{ years}}$$

Calculation:

- The capital expenditure is material (\$25 million > 10% of \$90 million);
- Depreciation is \$4.5 million per year;
- In year 15, the undepreciated capital for the pipeline is \$22.5 million;
- The capital addition is material (\$25 million > \$22.5 million), so the total is depreciated over 20 years:
 - = \$2.375 million/year

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.

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 cost of each system (electricity or steam) can then be allocated between its OSR Project and non-project uses, based on the measured use of each product.

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:

1. 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.
2. 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 5.3.1.3.1 of the Oil Sands Royalty Guidelines 2006.
3. Cost rules for Sales of Cogeneration Plants, [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:
 - Fuel Consumed for Process Steam Generation vs. Total Fuel Consumed by the Cogeneration unit
 - 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.
 - 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
 - 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 divided between steam and electricity.
3. Allocate the dedicated components of the Cogeneration system into electricity only, steam only, and shared.
 - Final allocation of components must be approved by Oil Sands Strategy and Operations Division.
 - 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.
 - Eligible maintenance and repair costs on a component will be considered an operating cost of that component.
 - 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 Royalty Project vs. Non Royalty project.
 - Measured steam use or engineering design steam use
5. Allocate the Electricity use by Royalty Project vs. Non-Royalty project.
 - 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.

5.4.3 Valuing NAL Electricity and Steam

The value of NAL electricity and steam must be determined when:

- i. They are provided to a royalty Project by a non-project asset (Allowed cost)
- ii. 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:
 - a. 85% of the capacity rating of the steam system
 - b. The actual throughput of the steam system

This reflects the determination that the base load of a steam plant is assumed to be 85% of its maximum capacity rating, for the purpose of determining annual capacity.

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

1. 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.

2. 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

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 oil sands 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 Strategy and Operations Division, and a detailed component allocation methodology for each system will be developed.

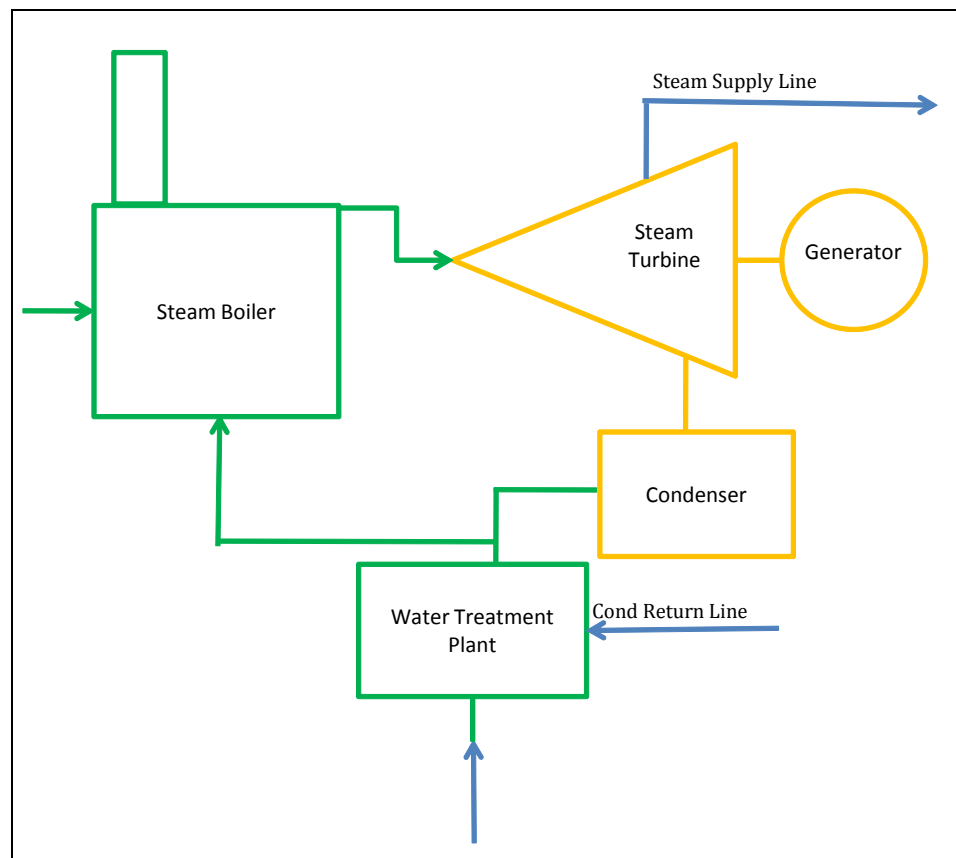
5.4.4.1 Non-Gas Turbine Based, Combined Heat and Power (CHP) system

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 Royalty Project (primarily a steam supply line from the Steam Turbine to the Royalty Project and a condensate return line from the Royalty Project to the Water Treatment Plant or the Condensate Storage Tank)
- Any maintenance costs associated with these pieces of equipment

3. Costs Allocated to the Electricity System

- Steam Turbine, 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, HP 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

A steam plant running at or above 85% capacity is considered to be operating at its base load (that is, at or near its capacity). When the annual capacity factor is greater than or equal to 85%, annual capital costs are applied on throughput.

Operating costs are based on throughput, so the average operating cost profile remains the same no matter the end user. When the annual capacity factor is below 85%, the Project is subject to review at the Minister's discretion.

Annual Capacity Factor

This ratio is calculated by dividing actual energy or steam produced annually by the amount of steam the plant would have produced had it operated at its maximum continuous rating for the whole year.

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”](#).)

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 so reduce risk.

Revenues, payments, and costs related to transactions entered into to hedge price risk are generally not included in calculations under the OSRR’09. 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 guaranteeing its future price for bitumen by entering into a forward contract to sell at a fixed price, and delivering 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) – Schedule Item 56

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.
 - 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 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 *OSRR’09* 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 horizontal crude bitumen production wells that have been drilled across the boundaries of adjacent OSR Projects. Usually, the same operator operates both Projects. The horizontal 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 problem.

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 open borehole in each Project.

The allocations between two Projects A and B should be calculated as follows:

Project A Allocation Factor = Length of open borehole on Project A / Total length of open borehole;

Project B Allocation Factor = Length of open borehole on Project B / Total length of open borehole;

If 75% (for example) of the open borehole 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

Another unique type of well can arise when 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 *Oil Sands Royalty Regulation, 2009 (AR 223/2008)* and the *Oil Sands Allowed Costs (Ministerial) Regulation (AR 231/2008)*. 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 (NAL) transactions, the Minister may need to determine the fair market value (FMV) 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 NAL transaction, and must be valued in accordance with approved NAL cost rules.

These rules for NAL 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 Figure 6: "Cost rules for non-arm's-length good, service, or asset acquisition", shows how the rules are applied.

Similarly, where assets of a project are disposed of to, or provide services for, an affiliate, the resulting ONP revenue must be established according to the appropriate NAL revenue rules. Again, 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 company is considered affiliated with another company 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:
 - i. the person and that other person are not dealing at arm's length

- ii. the person has an equity percentage in that other person that is not less than 10%, or
- iii. 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) through 2(6)

A transaction is considered to be a NAL 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, or
 - (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 subclause (i).

Any transactions to which the only parties are the Crown and another party are considered to be arm's length transactions.

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 an NAL 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 NAL transaction under section 2(3) of the OSRR'09, 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 he based his 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 NAL 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 NAL costs are set out in Division 2 of the Oil Sands Allowed Costs (Ministerial) Regulation. These NAL cost rules also apply in the calculation of "handling charges" as defined in section 32(1)(a) of the *OSRR'09*, and "BRC" and "GRC" as defined in section 5(3) and 5(4) of the *BVM Regulation*.

When valuing the cost of a good, service, or asset provided to an oil sands Project in a NAL transaction, we need to consider whether the item provided is a capital asset, 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 NAL 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

In a case where the Minister is satisfied that a FMV can be determined for:

1. the amount of a cost, where the cost is not 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 FMV determined by the Minister.

Note:

For the purpose of establishing a FMV for a good or service (other than pipeline transportation), the Minister will generally consider, without limitation, a published index of prices for the good or service, a price for the good or service determined under a regulation of the Government of Alberta or Canada, or an average of arm's length prices for the good or service.

In setting a FMV for a NAL 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 by a regulatory authority,
2. the tariff is subject to regulation by complaint, is published, reasonable, non-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 transported are done so 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 FMV 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 allowing for 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.

To record this transaction, the originating OSR Project should report a consideration (ONP) for the asset and the receiving OSR Project should report a cost.

In such a case, the Minister may determine (under section 19(4)), that the FMV 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

In a case where the Minister has determined that a FMV 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 FMV 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:

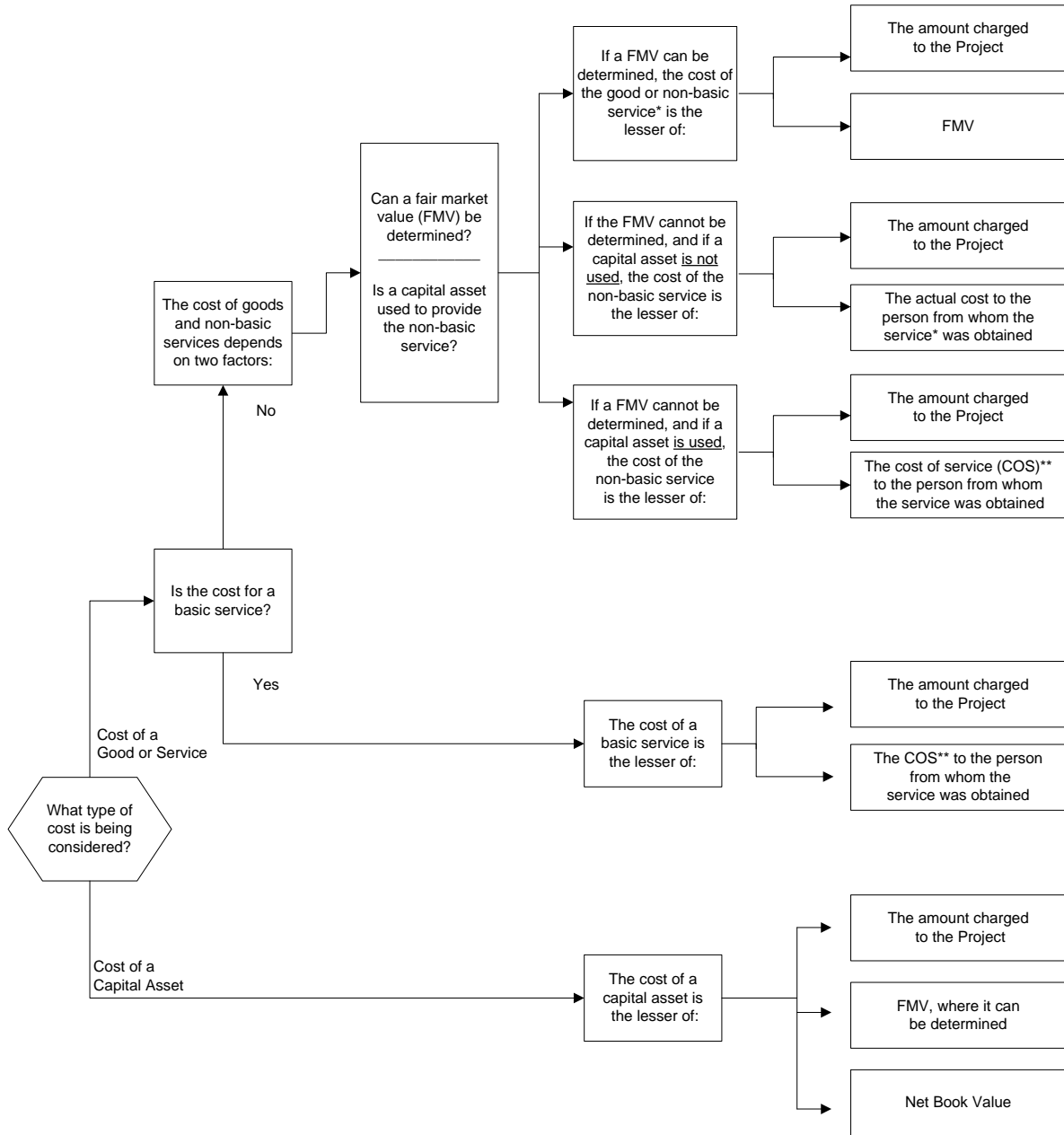
1. the amount charged for the service, and
2. the cost of service of the provider of the service.

Definition:

"Cost of service" means the actual costs incurred by the provider of the service, except that the portion of the actual cost related to the use of a capital asset is an amount in respect of depreciation as determined by the Minister, and a rate of return on the undepreciated capital cost of the asset as determined by the Minister.

6.3 Cost Rules for Non-Arms 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.

7. Administration and Enforcement

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 35 to 49

Effective January 1, 2009, the Crown's royalty share is calculated based on royalty rates calculated from WTI oil prices in Canadian dollars (\$Cdn). Royalty compensation, or instalments, is paid monthly by operators.

- For **Pre-Payout Projects**, the applicable Crown royalty share and royalty compensation are calculated 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 WTI price for the month.

- For **Post-Payout Projects**, the applicable Crown royalty share and compensation in respect of royalty for a Period, are calculated as the greater of:
 - the post-payout gross royalty rate, which varies from 1% to 9% based on the WTI price for the month, or
 - the post-payout net royalty rate for the period, which varies from (25% x NR/GR) to (40% x NR/GR), depending on the WTI price.
- Post-payout Projects are required to make monthly good faith instalments towards their royalty for the period. These estimates are also based on the greater of the gross and net royalty rates. Each month, estimated post-payout gross and net royalty rates are published for use in the calculation of these instalments.

Royalty reporting requirements depend on whether or not a Project has reached payout. A Project is defined to have reached payout on the first day of the month during which, for the first time, its cumulative revenues equal its cumulative costs.

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/>), navigate to "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

What is a period?

Section 1(y) of the OSRR'09 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 PNCR. 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 PNCR. 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.

What is a month?

Section 3 of OSRR'09 defines a month, except as otherwise specified by the Minister, as the period of time that begins at 8:00 AM on the first day of the month and ends immediately before 8:00 AM on the first day of the next month.

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 "Our Business," then to "Oil Sands," then "[Forms.](#)"), however all submissions must be made through the secure web application Electronic Transfer System (ETS) in Excel format.

Please note these Excel spreadsheets will be downloaded into a database – therefore no revisions to the forms' formats are 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 to be in compliance with the filing deadlines. Penalties may be levied if the forms are missing or submitted late (OSRR'09 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 OSRR’09, learns of a material change or error in, or a material omission from, the information contained in that report, then an amended report containing the updated, corrected or missing information must be submitted to the Department.

- The operator must file the amended report by the last day of the month following the month in which, the operator or other person who furnished the report required to be replaced learns of the material change, error or omission in the information contained in that report,

If an operator or other person has received notice from the Department to furnish an amended report, the operator must submit an amended report 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 OSR 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 “Our Business”, then to “Oil Sands”, “Legislation and Policies”, and “[Information Letters](#)”.

7.3.2 Non-Project Well Events

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 27 and 28

In 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.

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 not later than the last day of the following month.

7.3.2.1 Determining the 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:

The quantity of marketable crude oil obtained at the wellhead of the well-event from which the crude oil is produced and recovered

multiplied by

The Crown royalty formula for the marketable crude oil

multiplied by

The Crown interest percentage for the subject well-event

multiplied by

The Unit Value where the unit value is calculated as:

- 1) If greater than 40% of the 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 crude bitumen dispositions are from arms-length transactions, then a FMV will need to 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.

In determining the unit value, the Minister will generally consider revenues from the disposition of the oil sands product during that month. The unit value must not 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.

Examples of the Conventional Oil Sands Royalty Reporting (PSR) 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 "Our Business," then to "Oil Sands," then "Forms."). However submission of the PSR form must be made through the secure web application Electronic Transfer System (ETS) submitted in Excel Format. See section [7.8 – "Royalty Reporting Formats and Timing"](#) and Appendix H for ETS – "File Naming Conventions".

Effective for Period after and including January 1, 2011, the following are data entry fields on the PSR form where the operator must report data. All other fields on this form are calculated fields.

- Activity ID
 - PSR ID – Account Name
- Project Name
- Operator Name & ID
- ERCB Approval No.
- Production Month/Year
- Par Price (\$/m³) (Ultra Heavy)
 - As published in the Petroleum Royalty Regulation Monthly Information Letter. This Information Letter provides the Crude Oil Category and Density, and the various prices for oil necessary to determine the royalty volume payable to the Crown.
- Well ID (format e.g. 00/00-00-00-000W0/0)
- Eligibility for NWRR/HONWRR Y(es)/N(o)
 - If well is eligible for New Well Royalty Rate Reduction (NWRR) Program or the Horizontal Oil New Well Royalty Rate (HONWRR), please input Y; if well is not eligible for NWRR or HONWRR, please input N.
 - Please refer to the Oil Royalty Program Report in Petroleum Registry of Alberta (PRA) to determine whether a well qualifies for NWRR. If you are unfamiliar with how to access this report in PRA or have inquiries regarding this report please contact Director, Resource Revenue and Operations, Oil Royalty Operations (See Appendix G, "Contact Information").

- The PSR form has been revised to include changes to the Oil Royalty formula introduced in the 2010 Competitiveness Review Project (CRP) (maximum Royalty Rate Percent reduction from 50% to 40%, and additional price component for par price of >\$535.00/m³), along with calculating crown royalty share at 5% royalty rate for wells that qualify under the NWRR and HONWRR programs.
- For additional information on the New Well Royalty Rate (NWRR) program go to the Department's website (<http://www.energy.alberta.ca/>), navigate to "About Us," then to "About Royalties," then "Frequently Asked Questions", then select "[New Well Royalty Rate](#)" or information on CRP navigate to "[March 2010 Energizing Investment Phase 1 Competitive Review News Release dated March 11, 2010](#)".
 - Cost Centre ID (6 digit identifier)
 - Battery ID (7 digit identifier)
 - Total Production (m³)
 - Crown Percent (e.g. 100.0000000%)
 - Sales Price (\$/m³)
 - Handling Charges (\$)
 - Contact information:
 - Prepared by
 - Telephone, Fax number and E-mail address

Note:

The PSR forms used prior to January 1, 2011 in reporting conventional oil sands royalty calculation (non-project well events) are still valid for amendment submissions and required to be filed for the time Periods specified.

- **File for periods after and including January 1, 2009 to December 31, 2010**
- **File for periods prior to January 1, 2009**

7.3.2.2 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 27(1) and section 38(2)

The PSR form reporting Conventional Oil Sands Royalty must be submitted by the last day of the month, following the production month. Royalty must be paid to the Crown no later than the last day of the following month in respect of the Crown's royalty share.

Interest is levied on unpaid royalties or underpayments of royalties payable (See section [7.11, "Interest"](#) – reference section 45(1)(a) of OSRR'09)

A penalty may be levied if the Monthly Royalty Report – Conventional Oil Sands Royalty form is missing or submitted late. (See section [7.10, "Penalties."](#))

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.

7.4 Reporting Requirements for Pre-Payout Projects

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 at a RCP for that product must be reported to the Crown 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 figures for the current and past months and estimated figures for future months. For the first time filing of a month's data, in the month column label that this reporting is actual reporting, i.e. "Act."

Effective January 1, 2009, the MRC form merged all data requirements, into one document to report pre-payout monthly royalty.

MRC reporting forms are available for download on the Department's website in Excel format (From the Department's website (<http://www.energy.alberta.ca/>), navigate to "Our Business," then to "Oil Sands," then "[Forms.](#)"), however all submissions of the MRC must be made through the secure web application System (ETS) in Excel format. See section [7.8 – "Royalty Reporting Formats and Timing"](#) and Appendix H for ETS - File Naming Conventions.

NOTE:

If the Minister is not satisfied with the accuracy of the estimated data, the Minister has the ability to substitute his estimate for the data contained in a MRC, and will provide notice to the operator of the amount that has been substituted.

The Project information is to be reported on one MRC-1 Pre-Payout --- Monthly Royalty Calculation.

The Project operator who completes the MRC must include contact information such as name, e-mail address, telephone number and date prepared. (See section 7.8.4.1 - "Required Information")

Effective January, 2010, the following are data entry fields on the MRC-1 form where the operator must report data. All other fields on this form are calculated fields:

- 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 (\$)
- Non-Arm's Length (NAL) Sales, Handling Charges and Diluent information
 - 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 Adjusted 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
 - 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
 - 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.

- Allowed Costs
 - Project Operations (excludes cost of diluent)
 - Diluent – Calculated Field (The weighted average cost of diluent included with blended bitumen is deducted from the Crown's royalty share.)
 - 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.)
 - 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/>), navigate to "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".
- Previous Royalty Calculated for the month (Only required for the month if you are amending the MRC form)

Note:

The MRC forms used in reporting monthly royalty calculation prior to January 1, 2010 are still valid for amendment submissions and are required to be filed for the time Periods specified:

Effective January 1, 2009, the MRC form has been revised to correspond to OSRR'09 to report pre-payout monthly royalty effective production month January 1, 2009.

However, the MRC was revised in January 1, 2010 and therefore a separate MRC form is required to be filed for the Periods **January, 2009 to December, 2009 only**. The reporting criteria are similar to the above 2010-01 MRC form. Refer to the "Form Revision History" located on the 2010-01 form for all changes made.

Prior to January 1, 2009 the following MRC forms are still valid and are required to be filed accordingly.

MRC Pre 2009 - Use these forms to report pre-payout monthly royalty for production months prior to **January, 2009**.

- MRC-1a Pre-payout Monthly Royalty Calculation (Blended Bitumen)
- MRC-1b Pre-payout Monthly Royalty Calculation (Bitumen)
- MRC-1c Pre-payout Monthly Royalty Calculation (Synthetic Crude Oil)
- MRC-1d Pre-payout Monthly Royalty Calculation (Other Oil Sands Products)

MRC December, 2008 ONLY - Use these forms to report "December 2008" pre-payout royalty if Project has Pre 2009 inventory to report. Refer to the Oil Sands Information Bulletin's: [IB 2009-02](#) and [IB 2009-18](#) relating to "Pre-2009 Inventory reporting or section 6.13 Pre-2009 Inventory and Pre-2009 Transitional Inventory" for additional details.

- MRC-1a Pre-payout Monthly Royalty Calculation (Blended Bitumen)
– with Pre2009 Inventory
- MRC-1b Pre-payout Monthly Royalty Calculation (Bitumen)
– with Pre2009 Inventory
- MRC-1c Pre-payout Monthly Royalty Calculation (Synthetic Crude Oil)
– with Pre2009 Inventory
- MRC-1d Pre-payout Monthly Royalty Calculation (Other Oil Sands Products) –
with Pre2009 Inventory

7.4.1.1 Amendments

A Project operator must submit an amended MRC if the original submission's data was subject to an adjustment. Although the amount of royalty payable may change when the report is amended, the due date for payment remains the last day of the month following production.

If the adjustment results in an underpayment of royalty, 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.

Effective January 1, 2009, the Crown no longer pays interest on royalty overpayments made by the operator, whether the overpayment was made on an original or an amended MRC.

Note:

Any MRC amendment filed after its EOPS submission **must** be accompanied with an amended EOPS. If the EOPS is not received then the operator will be contacted informing them of the incomplete filing and that processing of the MRC will be delayed until the EOPS is received.

When reporting a prior month amendment in the current production Period, label the "month" as "Amendment" rather than "(Act)". In the next reporting Period, change the label "Amendment" back to "(Act)" for that month.

7.4.1.2 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 29(1) and section 38

Pre-payout MRC's must be submitted by the last day of the month, following the production month. Royalty calculated on the MRC's must be paid to the Crown no later than the last day of the following month in respect of the Crown's royalty share. (Reference section 33(1) of OSRR'09)

Interest is levied on unpaid royalties or underpayments of royalties payable (See section [7.11, "Interest"](#).)

A penalty may be levied if the MRC form is missing or submitted late. (See section [7.10 "Penalties"](#).)

For example, production and royalty for April is required to be reported by May 31. Penalties and interest may be levied if pre-payout MRC's are submitted late, or incomplete.

If the due date falls on a non-business day, the next business day will apply as a 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.

OSR Project Suspended but not Revoked:

- 1) Filings of the MRCs are still required until the ERCB and OSSO have revoked the scheme and OSR Project approvals.
- 2) Operators who submit 'Notification of suspension until further notice' in the 'Notes' section of the ETS Correspondence may discontinue filing the monthly reporting.
- 3) Failure to submit 'Notification of suspension until further notice' to the Department will result in penalties.

7.4.2 End of Period Statement Reporting Forms (Pre-Payout)

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 7.8.4.1, "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 "Our Business," then to "Oil Sands," then "[Forms.](#)") however submission of the EOPS must be made through ETS. See section [7.8 – "Royalty Reporting Formats and Timing"](#) and Appendix H for ETS – "File Naming Conventions".

7.4.2.1 Contents of Pre-Payout Reporting Package

7.4.2.1.1 Statement Requirement (PRE-1)

1. EOPS must be submitted to the Department's Oil Sands Strategy and Operations Division within 3 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 m³ 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 the Project reached the 1,590 m³ 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 sales are less than the 1,590 m³ 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 [7.13. “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](#))

Pursuant to Section 18(1), costs reported as incurred for the month must be paid within 90 days after the costs becomes payable to be eligible costs for the Period.

7.4.2.1.2 Reason for Amendment (PRE-1a)

This reporting form (schedule) is required only if the operator is amending the report. The operator must state the reason(s) for the EOPS amendment.

7.4.2.1.3 Project Payout Status (PRE-2)

This reporting form summarizes the cumulative cost and cumulative revenue for prior Periods, adds the allowed costs (including the cost of diluent), Project revenue and ONP for the current Period, and determines the net cumulative balance of the Project.

The Project operator must also provide an estimated payout date for the Project and identify the assumptions that underlie the estimate. The assumptions pertain to

- estimated sales price $\$/m^3$
- price differential
- production volumes
- Canadian exchange rate

7.4.2.1.4 Allowed Costs Summary (PRE-3 and PRE-3a)

All costs reported are in accordance with the *OSAC Regulation*.

These reporting forms report the summary and details for allowed costs incurred in the following categories:

- operating costs
- capital costs
- Project expansion PNCB
- capital with project expansion PNCB
- diluent costs
- royalty payable
- return allowance earned

Project operators must provide cost details using the detailed format provided in the PRE-3a form. Operating and capital costs reported for the month must comply with Section 18(1) of the OSRR'09.

- Pursuant to Section 18(1) Costs reported as incurred for the month must be paid within 90 days after the costs becomes payable to be eligible costs for the Period.

7.4.2.1.5 Return Allowance (PRE-4)

The monthly return allowance earned (See section [4.2.1, "The Opening Balance"](#)) is an allowed cost. Together with other allowed costs and royalty paid for that month, it is added to the previous month's cumulative cost to get the current cumulative cost for the Project.

Using the format provided in the PRE-4 form, Project operators must provide the following:

- Carry Forward "Cumulative Costs" from Previous Period
- Costs
 - Includes Operating, Capital, Project Expansion PNCB and Diluent.
 - Excludes Royalty and Return Allowance for the month
- Royalty Payable for the month
- Cumulative Revenue
- Net Cumulative Balance (base for Return Allowance) – calculated as the sum of the Carry Forward Cumulative Cost from the previous Period plus Costs plus Royalty Payable for the month minus Cumulative Revenue
- Long Term Bond Rate (LTBR) monthly rate % (Bank of Canada's)
- Return Allowance – calculated as the Net Cumulative Balance multiplied by the LTBR%.
- Cumulative Cost - calculated as the sum of the Carry Forward Cumulative Cost from the previous Period plus Costs Royalty Payable and the Return Allowance.

7.4.2.1.6 Revenue Summary (PRE-5)

This reporting form 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. ONP are added to the Project Revenue to determine the Project's cumulative revenue.

Revenues from ONP are further categorized 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

A revenue detail form is required for each leased oil sands product sold or disposed of by the Project operator.

7.4.2.1.7 Revenue and Royalty Details (PRE-6)

This form reports the Crown's royalty share payable for each leased oil sands product delivered and measured at the RCP during the production month whether or not the lessee has actually sold or otherwise disposed of those products.

EOPS details must reconcile to the latest MRC submission for the Period.

Indicating either Actual or Estimate for a reporting month, the reporting requirements for the revenue and royalty detail reporting on the EOPS PRE-6 form are:

- Production, AL (Arm's Length) Sales & Handling Charges for the reporting month
- Non-Arm's Length(NAL) Sales, Handling Charges and Diluent information
- Bitumen Adjusted BVM Price (\$/m³)
 - Bitumen adjusted BVM Price must be reported if the total third party dispositions (TPDT) (i.e. arm's length sales of product divided by product volumes at RCP) are less than 40%
- Other Oil Sands Product Fair Market Value (FMV) – (\$/unit)
- Bitumen Density (kg/m³)
- BVM Transportation Allowance (\$/m³)
- Diluent
 - Diluent in AL Sales Volume (m³)
 - Diluent in Volume at RCP (m³)
 - Diluent Value in AL Sales (\$)
 - Diluent Value in Volume at RCP (\$)
- Royalty Rate
 - 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/>), navigate to "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

Note:

The EOPS used in reporting the pre-payout end of Period royalty prior to January 1, 2009 are still valid for amendment submissions and are required to be filed for the time Periods specified:

EOPS Pre-Payout Pre 2009 - Use these forms to report pre-payout end of Period royalty prior to Period 2009.

- PRE-1 Auditor Letter Requirement
- PRE-2 Project Payout Status
- PRE-3 Allowed Costs Summary
- PRE-3 Supp-a – Allowed Cost Detail
- PRE-3 Supp-b – Allowed Costs Detail
- PRE-4 – Return Allowance
- PRE-5 – Revenue Summary
- PRE-6 – Royalty Summary
- PRE-6a – Royalty Detail (Blended Bitumen)
- PRE-6b – Royalty Detail (Bitumen)
- PRE-6c – Royalty Detail (Synthetic Crude Oil)
- PRE-6d – Royalty Detail (Other Oil Sand Products)

EOPS Pre-Payout 2008 ONLY - Use these forms to report pre-payout “2008” end of Period royalty if the Project has Pre 2009 inventory to report. Refer to the Oil Sands Information Bulletin’s: [IB 2009-02](#) and [IB 2009-18](#) relating to Pre-2009 Inventory reporting or section 6.13 “Pre-2009 Inventory and Pre-2009 Transitional Inventory” for additional details.

- PRE-1 Auditor Letter Requirement
- PRE-2 Project Payout Status
- PRE-3 Allowed Costs Summary
- PRE-3 Supp-a – Allowed Cost Detail
- PRE-3 Supp-b – Allowed Costs Detail
- PRE-4 – Return Allowance
- PRE-5 – Revenue Summary
- PRE-6 – Royalty Summary
- PRE-6a – Royalty Detail (Blended Bitumen)
- PRE-6b – Royalty Detail (Bitumen)
- PRE-6c – Royalty Detail (Synthetic Crude Oil)
- PRE-6d – Royalty Detail (Other Oil Sand Products)

7.4.2.2 Amendments

The production, revenue and royalty figures reported on an EOPS must reconcile to those submitted on the pre-payout Project's MRC reports.

- Project operators can file amendments to the MRC reports after the EOPS has been filed within the eligible Period (within 4 years of the end of the Period). However, the EOPS must also be amended to reconcile with the amended MRC report.
- If an operator's cost treatment, revenue valuation or any other adjustment is deemed by the Department's audit to be non-eligible for royalty reporting purposes, the operator must apply this audit adjustment to all future reporting periods and amend all reporting.

For operators who have 2008 inventories, any amendments that affect the average unit price within the 2009 MRC Period will require the operator to amend their 2008 valuation of inventory in the 2008 EOPS. See section [7.13 - "Pre-2009 Inventory and Pre-2009 Transitional Inventory"](#).

7.4.2.3 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 39

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 a due date.

Royalty must be paid to the Crown no later than the last day of the 4th month following the Period in respect of the Crown's royalty share. (Refer to section 33(2) of OSRR'09)

Interest is levied on unpaid royalties or underpayments of royalties payable. (See section [7.11, "Interest"](#).)

A penalty may be levied if the EOPS is missing or submitted late. (See section [7.10 "Penalties"](#).)

OSR Project Suspended but not Revoked:

- 1) Filings of the EOPS are still required until the ERCB and OSSO have revoked the scheme and OSR Project approvals.
- 2) Operators who submit 'Notification of suspension until further notice' in the 'Notes' section of the ETS Correspondence may discontinue filing the annual royalty reporting.
- 3) Failure to submit 'Notification of suspension until further notice' to the Department will result in penalties.

7.4.3 Reporting Requirements for Post-Payout Projects

Royalty calculations are submitted to the Department on a Good Faith Estimate (GFE) form. The financial information required on a GFE is more detailed than the information reported on the MRC forms submitted for pre-payout Projects. Actual figures for past months and estimates for future months must be included.

Both pre-payout and post-payout Projects must submit an Operator's Forecast report each year. (See section 7.5, "The Operator's Forecast")

GFE reporting forms are available for download on the Department's website in Excel format (From the Department's website (<http://www.energy.alberta.ca/>), navigate to "Our Business," then to "Oil Sands," then "[Forms.](#)"), however all submissions of the GFE must be made through the secure web application Electronic Transfer System (ETS). See section [7.8 – "Royalty Reporting Formats and Timing"](#) and Appendix H for ETS - File Naming Conventions.

Contact DOE Oil Sands Royalties Email:OSReport@gov.ab.ca for a revised spreadsheet, if you have product sales that are not included on the GFE product categories.

7.4.4 Monthly Good Faith Estimates Reporting Forms

For post-payout Projects, Good Faith Estimates (form GFE-1) are submitted each month. Like the monthly 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 figures for the current and past months and estimated figures for future months.

The Project operator who completes the GFE must include contact information such as; name, e-mail address, telephone number and date prepared. Refer to an itemized table, section 7.8.4.1, "Required Information" for a summary of required form information.

Note 1:

Note the GFE for a month cannot be amended in a month that has passed. Adjustments must be incorporated into the current month of the Period. If an adjustment is required in a month in a Period that an EOPS has been filed, the adjustment is reported in the EOPS.

Note 2:

- Reasonable estimates must be provided as the estimates directly affect the amount of royalty estimated and remitted for the Period.
- 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.

Effective January 1, 2010, 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:

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 (m³)
- Crude Bitumen Volume at RCP (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 (\$)
- Non-Arm's Length (NAL) Sales, Handling Charges and Diluent information
 - 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 Adjusted BVM Price (\$/m³)
- Other Oil Sands Product Fair Market Value (FMV) (\$/unit)
- Bitumen Density (kg/m³)
- BVM transportation allowance (\$/m³)
- 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
 - 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.
- Allowed Costs
 - 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
- Other Net Proceeds (ONP)
 - Excess of Previous Period's ONP over Total Allowed Costs (AC)
 - Earned (in the Period)
 - Allowed costs can be reduced by the total amount of other net proceeds 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 / (Net Loss)
 - 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 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 Instalment. For production months previous to the current production month, input the original Royalty Calculated amount (i.e. monthly instalment calculated previously) as the Monthly Royalty Instalment.
 - 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/>), navigate to "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

Note:

The GFE used in reporting the Post-Payout monthly royalty for production months prior to January 1, 2010 are still valid for amendment submissions and are required to be filed for the time Periods specified:

GFE Effective 2009, revised January 1, 2009 to report post-payout monthly royalty effective production month January 1, 2009.

However, the GFE was revised in January 1, 2010 and therefore a separate GFE form is required to be filed for the Periods **January, 2009 to December, 2009 only**. The reporting criteria are similar to the above January, 2010 GFE form. Refer to the "Form Revision History" located in the January, 2010 form for all changes made.

GFE Pre-2009 – Use this form to report post-payout monthly royalty for production months prior to January 1, 2009.

7.4.4.1 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 38

Good faith estimates must be submitted by the last day of the month following the production month. For example, production and royalty payable for April would be reported by May 31.

Royalty instalments calculated on the GFE's must be paid to the Crown no later than the last day of the following month in respect of the Crown's royalty share. (OSRR'09 - section 33(1)).

Interest is levied on unpaid royalties or underpayments of royalties payable. (See section [7.11, "Interest"](#)) (OSRR'09 - section 45(6))

A penalty may be levied if the GFE form is missing or submitted late. (See section [7.10 "Penalties"](#)) If the due date falls on a non-business day, the next business day will apply as a due date.

Exceptions

Newly approved or amended Projects normally have retroactive effective dates. 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 April 30th. Due dates for subsequent monthly reports would follow the regular schedule.

7.4.5 End of Period Statements Reporting Forms (Post-Payout)

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 such as; name, e-mail address, telephone number and date prepared. Refer to an itemized table, section 7.8.4.1, "Required Information" for a summary of required form information.

EOPS (post-payout) are available for download on the Department's website in Excel format (From the Department's website (<http://www.energy.alberta.ca/>), navigate to "Our Business," then to "Oil Sands," then "[Forms.](#)"), however all submissions of the EOPS must be made through the secure web application Electronic Transfer System (ETS). See [section 7.8 – "Royalty Reporting Formats and Timing"](#) and Appendix H for ETS - File Naming Conventions.

7.4.5.1 Contents of Post-Payout Reporting Package

7.4.5.1.1 Statement Requirement (PST-1)

1. EOPS must be submitted to the Department's Oil Sands Strategy and Operations within 3 months after the end of each Period.
2. If the aggregated quantity of bitumen measured at the royalty calculation point during the Period is greater than an average of 1,590 m³ 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 the Project reached the 1,590 m³ per day threshold, the external 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 sales are less than the 1,590 m³ 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"](#))

3. 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 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 2009-03](#)).

4. Pursuant to Section 18(1) Costs reported as incurred for the month must be paid within 90 days after the costs becomes payable to be eligible costs for the Period.

7.4.5.1.2 Reason for Amendment (PST-1a)

This reporting form (schedule) is required only if the operator is amending the report. The operator must state the reason(s) for the amendment.

7.4.5.1.3 Royalty Payable (PST-2)

This reporting form identifies the royalty payable and the royalty rate used to calculate this amount. Royalty payable is the greater of the Project's gross revenue royalty or the net revenue royalty. These values are carried forward from the Royalty Calculation – PST-3 form.

The total royalty payable for the Period is reconciled to the total royalty actually paid by the operator. Any difference must be paid by the operator or refunded by the Department by the last day of the 4th month following the end of the Period.

Contact information is required on this form (e.g. Name, Company, contact number and date prepared)

- 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/>), navigate to "Our Business", then to "Oil Sands", "Legislation and Policies", and "[Information Letters](#)".

7.4.5.1.4 Royalty Calculations (PST-3)

This reporting form calculates royalty based on Gross Revenue percentage (RG %) of the Project's gross revenue and on Net Revenue percentage (RN %) of the net revenue. The greater of these amounts is the royalty payable, which is entered on form PST-2. 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.

7.4.5.1.5 Allowed Cost Summary (PST-4 and PST-4a)

These reporting forms provide a summary and details of the allowed costs incurred by the Project.

The PST-4 allowed costs summary requirements are:

- Cumulative Balance Carried Forward Upon Payout
- operating costs
- capital costs
- Project Expansion PNCB
- Capital with Project Expansion PNCB

- the cost of diluent
- the return allowance on the previous Period's net loss
- the net loss carried forward from the previous Period
- the excess gross revenue royalty paid in the previous Period

Project operators must also provide cost details. Using the - Allowed Costs Details form (PST-4a) the operator must include the following information

- breakdown of allowed costs per month
 - Operating
 - Capital
 - Project Expansion PNCB
 - Diluent

Note:

Pursuant to Section 18(1) Costs reported as incurred for the month must be paid within 90 days after the costs becomes payable to be eligible costs for the Period.

7.4.5.1.6 Other Net Proceeds (ONP) (PST-5)

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 23

This reporting form identifies ONP generated by the Project. The categories listed on the form are intended as examples. Project operators may use categories that reflect their particular operations.

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.

7.4.5.1.7 Return Allowance (PST-6)

This reporting form 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.

7.4.5.1.8 Project Revenue (PST-7)

This reporting form summarizes the total revenue generated for each month of the Period. Project revenue less the cost of diluent determines the gross revenue of the Project.

The revenue details for each number on this schedule are reported on the PST-7a form. A revenue detail schedule (similar to pre-payout form PRE-6) is required for each oil sands product sold or disposed of by the Project operator.

7.4.5.1.9 Carry Forward Amounts (PST-8)

This reporting form identifies four cost and revenue amounts that can be carried forward to the next Period as allowed costs:

- 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
- the excess of ONP over total allowed costs (carried forward to the next Period's other net proceeds)

Note:

The EOPS used in reporting the post-payout end of Period royalty prior to January 1, 2009 are still valid for amendment submissions and are required to be filed for the time Periods specified.

EOPS Post-Payout Pre 2009 - Use this form to report post-payout end of Period royalty prior to Period 2009.

- PST-1 Auditor Letter Requirement
- PST-2 Royalty Payable
- PST-3 Royalty Calculations
- PST-4 Allowed Costs Summary
- PST-4 Supp-a – Allowed Cost Details
- PST-4 Supp-b – Allowed Costs Details
- PST-5 – Other Net Proceeds
- PST-6 – Return Allowance
- PST-7 – Project Summary
- PST-7a – Revenue Detail (Blended Bitumen Sales)
- PST-7b – Revenue Detail (Bitumen Sales)
- PST-7c – Revenue Detail (Synthetic Crude Oil Sales)
- PST-7d - Revenue Detail (Other Oil Sand Product Sales)
- PST-8 – Carry Forward Amounts

EOPS Post-Payout 2008 ONLY - Use this form to report post-payout "2008" end of Period royalty if Project has Pre 2009 inventory to report.

- PST-1 Auditor Letter Requirement
- PST-2 Royalty Payable
- PST-3 Royalty Calculations
- PST-4 Allowed Costs Summary

- PST-4 Supp-a – Allowed Cost Details
- PST-4 Supp-b – Allowed Costs Details
- PST-5 – Other Net Proceeds
- PST-6 – Return Allowance
- PST-7 – Project Summary
- PST-7a – Revenue Detail (Blended Bitumen Sales)
- PST-7b – Revenue Detail (Bitumen Sales)
- PST-7c – Revenue Detail (Synthetic Crude Oil Sales)
- PST-7d - Revenue Detail (Other Oil Sand Product Sales)
- PST-8 – Carry Forward Amounts

7.4.5.2 Amendments

The Department will accept amendments to the EOPS for a post payout Project within the eligible Period (within 4 years of the end of the Period).

7.4.5.3 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 39

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.

Penalties and interest may be levied if EOPS are submitted late. (See section [7.10 "Penalties"](#) and section [7.11, "Interest"](#))

OSR Project Suspended but not Revoked:

- 1) Filings of the EOPS are still required until the ERCB and OSSO have revoked the scheme and OSR Project approvals.
- 2) Operators who submit 'Notification of suspension until further notice' in the 'Notes' section of the ETS Correspondence may discontinue filing the annual royalty reporting.
- 3) Failure to submit 'Notification of suspension until further notice' to the Department will result in penalties.

7.5 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 the figures submitted.

Operator's Forecasts are used to estimate oil sands royalty revenues expected by the Crown for the current calendar year plus the next 9 calendar years, and to inform the Crown as to when the Project payout date is expected to occur.

Operator's Forecasts should be submitted to the Director, Business Design and Evaluation, Oil Sands Strategy and Operations Division. (See Appendix G, "Contact Information")

Note:

In some cases, the Department may request the operator to provide a presentation to support the submitted forecasts.

7.5.1 Operators Forecast Submission Procedures

Step 1: Complete the Operator's Forecast Report

The Operator's Forecast Report is available for download on the [Department's website](#) in Excel format (From the Department's website (<http://www.energy.alberta.ca/>) navigate to "Our Business", then 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 7.8– "Royalty Reporting Formats and Timing"](#) for additional information.

Note:

In the application form make sure to check the Operator's Forecast box as this will allow you to submit the Operator's Forecast Report.

7.5.2 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 Name

Main Contact information such as; name, position, e-mail address, telephone number and date prepared (as well as "alternate contact" information)

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 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 wt%) 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 have substantial capital additions towards the end of the 10 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:
 - Diluent volumes used at RCP - Type of Diluent, and
 - Diluent Price - Pricing Location
- 7. Other Product Revenues (must specify the products)
 - Other product revenues include the Operator's Forecast of revenues from oil sands by-products such as sulphur and coke.
 - "Other product revenues" and "other net proceeds" are mutually exclusive.
- 8. Total Natural Gas Volumes Used for Bitumen Production
 - Projects that use natural gas must report the total volume (including solution gas volumes used, if applicable).
 - For cold production Projects report the fuel gas used on this line.
- 9. Solution Gas Volume Used (GJ/year)
 - 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 an 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

7.5.3 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. If, after submitting their forecast, an operator becomes aware of material changes or errors in the forecast, or a new expansion is planned that was not incorporated in the forecast, the operator must notify the Department within 30 days and re-submit a revised Operators Forecast within 30 days after the notification date.

7.5.4 Timing

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 37

Operators' forecasts must be submitted by December 15 of each year. If the 15th 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 penalties. (See section [7.10 "Penalties"](#) and section [7.11, "Interest"](#))

7.6 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). Penalties may be imposed if required reports are late. (See section [7.10 "Penalties"](#) and section [7.11, "Interest"](#))

7.7 Enhancement Reporting

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 38.1(1)

7.7.1 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 base.

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 "Our Business," then 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 7.8– "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; OSSO has locked the form formats to ensure data integrity.

Additionally, workbooks must be submitted in excel - xls format instead of xlsx until notification by OSSO of software upgrades.

An online training module is available for the submission process. ([Energy Online Training Portal](#)) To access the portal, click on the provided link, select Knowledge Resources, and then scroll to the CARE resource titles to view the training modules.

CARE 01. – ETS Correspondence	ETS Correspondence - General training course that provides information on how to use the Electronic Transfer System (ETS) for submitting Cost Analysis and Reporting Enhancements (CARE) forms to the Alberta Energy.
CARE 02. – CARE Online Training	CARE Online Training provides the procedures for submitting Cost Analysis and Reporting Enhancements (CARE) forms to the Alberta Energy.

7.7.2 CARE 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).

7.7.3 Key Reasons for Information Reporting

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.

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: OSRR'97, OSRR'09, Bitumen Valuation Methodology (Ministerial) Regulation* and *Oil Sands Allowed Costs (Ministerial) Regulation*, the OSR Guidelines and the Project description and conditions of each OSR Project Approval.

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.

7.7.4 Timing – CARE Filing Timeline and Timetable

CARE reporting commenced September 30, 2009, and was effective for the Periods 2009 and 2010, with individual files for each form type. Effective with the 2011 reporting Period, OSSO re-designed the CARE form formats into Excel workbooks designed for CARE – Costs, Project and Revenue reporting which encompass all of the previous forms.

Note: Amendments to the CARE forms for the reporting Periods 2009 and 2010 must be completed in the original forms' format.

Refer to Appendix E for the "CARE Timelines and Timetable" for filing details.

CARE - COST (In-Situ and Mining Projects) workbook is filed quarterly (on a cumulative year to date basis).

- The CARE – Allowed Cost / End of Period Statement Reconciliation form has been included in the CARE-COST Workbook and is completed annually. It is auto-populated with the CARE Operating and Capital Costs reported in each quarter.

CARE – REVENUE reporting is filed quarterly (detailed by month basis).

CARE – PROJECT reporting is filed annually (year to date basis).

Amendments to the COST and REVENUE workbooks can be trued up in the next quarter's filing. Specifically for CARE COST workbooks, amendments can be trued up with the last quarter filing where reconciliation to the End of Period Statements (EOPS) is required.

An amendment to the CARE PROJECT workbook is full form replacement.

OSR Project Suspended but not Revoked:

- 1) Filings of the CARE reports are still required until the ERCB and OSSO have revoked the scheme and OSR Project approval.
- 2) Operators who submit 'Notification of suspension until further notice' in the 'Notes' section of the ETS Correspondence may discontinue filing the CARE reporting.
- 3) Failure to submit 'Notification of suspension until further notice' to the Department will result in penalties.

7.7.5 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.

7.7.5.1 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

7.7.5.2 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)]

7.7.6 Project Data Workbook: Volumetric, Operations, Reserves, Deposit and Reservoir Data Reports

7.7.6.1 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.

- Filed Annually – 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.

7.7.6.2 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).

7.7.6.3 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.

7.7.6.4 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 these data must be reported separately for each facility; or if reported on an ERCB 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.

7.7.6.5 Volumetric Data – Mining & In-Situ Projects

At an OSR Project level and ERCB 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 Energy Resources Conservation Board (ERCB) and are identified specifically in the ERCB Directive 017 – Measurement Requirements for *Upstream Oil & Gas Operations*.

- For integrated Projects with both bitumen production and upgrading facilities these 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.

7.7.7 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.

7.7.7.1 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 stream can be entered in the ‘Other Stream’ cell. Note that stream abbreviations are restricted to a 5 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:
 - o 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 – a measure of the mass of a substance per unit of volume (i.e., kg/m³) the mass occupies, 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.

7.7.7.2 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.

7.7.7.3 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 DiluentType 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)

7.7.7.4 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.

7.7.7.5 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 DiluentType 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.

7.7.7.6 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.

7.7.7.7 Western Canadian Select (WCS) Sales

Operators that have WCS sales are required to file this form.

- Filed quarterly

7.7.8 CARE Statement of Approval

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 38(5) and 39(3)

The CARE workbooks 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 approval can be provided on a separate document. ([Refer to Information Bulletin \(IB\) 2009-03](#))

7.8 Royalty Reporting Formats and Timing

7.8.1 Oil Sands Report Submissions Using Energy's Electronic Transfer System (ETS)

Royalty reports must be submitted using the Department's secure web application, Electronic Transfer System (ETS). This includes the submission of monthly (MRC, GFE and PSR) and annual (EOPS and Operator's Forecasts) royalty forms and related correspondence (Statement of Approval, Independent Auditor Opinion, etc.). The Cost Analysis and Reporting Enhancements (CARE) forms must also be submitted through ETS.

Royalty reporting forms can be downloaded from the [Department website](#) as PDF or Excel files. The latter include pre-programmed formulae so that the required calculations are done automatically once monthly volumes are inputted.

Project operators are required to use only ETS for their Royalty reporting submissions. If the unlikely event there are temporary technical problems with ETS at the time a submission is being made, and the technical problems cannot be resolved by the filing deadline, then the email process will be made available for Project operators to submit their reports. 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".

7.8.2 ETS Access

Operators must have an ETS Account with the Department in order to submit royalty reports. Operators who do not have an ETS Account will need to contact the Department's Client Registry at 780-422-1395 (toll free 310-0000); to obtain one before the operator can access the Correspondence folder in ETS.

To get access to the Electronic Transfer System, an ETS account Set Up / Change Form must be submitted to the Department. The majority of our clients have access to ETS with various permissions to provide information or request a service from the Department. However, their permissions need to be enhanced to include access to the Correspondence folder.

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 Knowledge Resources, and then scroll to the ETS resource titles to view the training modules.

7.8.3 Royalty Form Types for ETS Submission

Operators must upload their monthly and annual royalty reports using the Send Form submission screen in the Correspondence folder.

The royalty reports and related documents that can be uploaded are identified in the Form Type list in the Send Form submission screen.

All Oil Sands Royalty submissions are made by Form Type. Operators may submit multiple files for each Form Type in a single submission. The maximum size for a submission is approximately 3.5 MB. Zip files are acceptable.

To enable better management of the ETS submissions, operators are required to use the standardized file naming convention established by the Department. Refer to the tables in Appendix H – “ETS File Naming Conventions” where the naming conventions for each report type are addressed. The actual file name for each submission **must contain**, at least, the required naming conventions established in this table.

Project operators must select the appropriate form type for the submission that is being made. To facilitate the management of files in ETS, Project operators must name their ETS submission files in accordance with the file naming conventions.

Questions on the ETS submission process for monthly and annual royalty reports can be directed to the royalty administrators in Oil Sands Strategy and Operations or to the OS Reporting Mailbox (OSReport@gov.ab.ca).

7.8.4 Form Types for ETS Submission

1. Project Applications ([Section 3.3.2](#)), must be submitted electronically through the Department's ETS. The applicant needs an authorized ETS Account prior to accessing the OASIS (Oil Sands Administration & Strategic Information Systems) service where the Project Application is available.
2. For submitting CARE reporting - refer to Appendix H for ETS File Naming Conventions.
3. For the Operator's Forecast Report, when saving the form in Excel format, you must use the following naming convention: OSR Project Number, Year, and Report Name.

Example: OSR015_2009_Operators_Forecast.xls

7.8.4.1 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 equals the current production Period (year and month)	the Period start and end dates	the report month (which equals the current production Period (year and month)	the Period start and end dates
ERCB Approval number	N/A	ERCB Approval number	N/A
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
Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or SO*	Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or SO*	Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or SO*	Signature of the operator or representative & accompanied by a statement of approval* by the CFO* or SO*
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 m ³ /day	N/A	auditor's letter required if crude bitumen measured at the RCP average more than 1,590 m ³ /day
* must be approved in advance by the Department (refer to IB 2009-03)			
* CFO – Chief Financial Officer			
* SO – Senior Officer			
* ETS – Electronic Transfer System			

7.8.4.2 Reporting Standards

All royalty-related reports submitted to the Department must comply with the following standards.

7.8.4.2.1 Volumetric Reporting

Volumes of bitumen, diluent and synthetic crude oil are expressed in cubic metres (m^3) to the nearest tenth of a cubic metre. For example: 66.9 m^3 .

Quantities of sulphur are expressed in tonnes to the nearest tenth of a tonne. For example: 34.9 t.

7.8.4.2.2 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).

7.8.4.2.3 Negative Values

Negative values, whether monetary or volumetric, are indicated with a leading negative sign (e.g. -\$132.50 or -133.5 m^3).

7.8.4.3 Submissions

The Department is not liable for report submissions that are lost in transit.

It is the responsibility of the Project operator to ensure that Project royalty reports reach the Department by the specified due dates. Penalties and interest may be imposed if required reports are late. (See section [7.10 "Penalties"](#) and section [7.11, "Interest"](#))

The software used must be compatible with the version of Excel used by the Department. As of printing, this is Microsoft Excel 2007 or previous Excel versions.

7.8.5 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 December 15 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 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 2009 was 400.0 m³, royalty in respect of that product is payable on or before April, 2010.

Post-Payout Projects are required to make instalment payments each month. (See section [4.5 – "The Royalty Calculation for Post-Payout Projects"](#))

NOTE:

Penalties and interest may be levied if the required reports are submitted late. (See section [7.10 "Penalties"](#) and section [7.11, "Interest"](#))

7.9 Royalty Payment

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 29, 31, and 33

7.9.1 Application of Payments

Oil Sands Royalty Regulation, 2009 (AR 223/2008), sections 46

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) 1st, on penalties owing
- b) 2nd, on interest owing
- c) 3rd, on royalty compensation or proceeds of royalty owing, respectively.

7.9.2 Methods of Payment

All remittances in respect of Crown royalty must be payable to the Minister of Finance, Province 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 four ways:

- by cheque through the mail, or by courier, or dropped off at AMEC place in Calgary (see address below)
- by Electronic Funds Transfer (EFT) to the account of the Minister of Finance:

Bank Name:	Canadian Imperial Bank of Commerce (CIBC)
Beneficiary Name:	PT-Mineral Revenue Account
Bank Address:	10102 Jasper Avenue Edmonton Alberta

Bank No:	0010
Swift Code:	CIBCCATT
Transit No:	(00059)
Account No.	00-54305






- by automatic debit

- by direct deposit, using a RapidTrans deposit slip:

RapidTrans deposit slips are available from the Calgary Information Centre at

Alberta Energy
 Calgary Information Centre
 AMEC Building
 300, 801 - 6 Avenue SW
 Calgary, Alberta Canada T2P 3W2
 Telephone (403) 297-8955
 Fax (403) 297-8954

Figure 1: The information required for oil sands royalty payments.

Alberia ENERGY RAPIDTRANS DEPOSIT SLIP		CLIENT ACCOUNT NUMBERS AND IDs	PAYMENT TYPE	LIST CHEQUE & AMOUNTS (\$)	
For deposit to the  the Provincial Treasury at CANADIAN IMP. BANK OF COMMERCE		G94 123456 Client ID 0ZZ4	G94	1,000	00
BRANCH		G94 			
DATE		OTHER (PLEASE IDENTIFY) eg. GAS, PCR, OSR Gas 93 ZZ4	GAS	549	50
ACCOUNT # 		PCR ZZ4	PC1	236	23
ENTER HANDWRITING NO. 					
JANE DOE 555-4321					
CREDIT FROM ACCOUNT: 					
694 3211					
AYER: PLEASE FAX COPY OF YOUR RAPID TRANS TO: 403-422-4281 - ATTN: CASHIERS					

CLIENT ACCOUNT NUMBERS AND IDs	PAYMENT TYPE	LIST CHEQUE & AMOUNTS (\$)
G94 ← Only applicable if reporting gas royalty		
G94		
G94		
OTHER (PLEASE IDENTIFY) eg. PCR, FOR PSR AssignedName OSR 123	PSR OSR	10,000.00 1,123,456.00
↑ Oil Sands Royalty Payments are reported under "OTHER"		
TOTAL DEPOSIT		\$ 1,133,456.00

7.9.3 Required Information

Oil sands royalty payments must include the following information:

- the payment date
- the name of the payer and operator ID
- the activity ID that identifies the name or number assigned to the Project (e.g. OSR015)
- the dollar amount for each activity ID, if the payment is for more than one Project
- the payment total

If the payment is made by direct deposit, the required information must be entered directly on the RapidTrans slip.

If the payment is by mail or electronic transfer of funds, the required information can be faxed to the Cashiers Financial Services Group at 780-422-4281.

If the above information is not provided, the payment may be rejected and penalties and interest could be assessed.

7.9.4 Information and Assistance

For assistance in completing RapidTrans slips for oil sands royalty payments, contact the "Oil Sands Royalty Account Inquiries" team. (See Appendix G, "Contact Information" or via the OS Reporting Mailbox - OSReport@gov.ab.ca)

For information about signing up for RapidTrans payments, contact the Department's Financial Services Branch. (See Appendix G, "Contact Information")

7.10 Penalties

Oil Sands Royalty Regulation, 2009 (AR 223/2008), section 44

1. Penalties will be assessed against Project operators who fail to provide the required Operator's Forecasts, Monthly Royalty reports, EOPS and Enhancement Reporting with complete information, and in the proper format, by the prescribed due dates. (See section [7.10.1, "OSR Due Date Chart – Royalty Reports"](#)). This includes the statement of approval or the auditor's opinion. Project operators are required to file monthly reports regardless of the values reported. Penalties also apply to operators who fail to provide monthly conventional oil sands royalty reports (PSR) by the prescribed due dates.

If a Project operator has been notified by the Department that an amendment is required, and the amendment 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.

- the department will issue a \$5,000 penalty for each month or partial month where the required report continues to be late or is incomplete.
- penalties must be paid within 30 days of receiving notice of the penalty, or interest will be calculated on unpaid penalty amounts.

If an operator has been penalized for failing to file a report, they will not be further penalized for failing to file the statement of approval or auditor's opinion required to accompany the report. However, if a report is submitted to the Department accurately and by the due date but without the required auditor's opinion, a penalty will be charged.

2. Penalties will be assessed against Project operators who fail to provide any required Ad hoc reports that the Department requests. This may include other supporting documentation for a royalty calculation (e.g., supporting details for a unit price calculation). Once an operator is advised by the Department of a reporting deficiency or has been requested to supply additional information, the operator must supply the information within the timeframe identified in the Department's request.
 - A \$5,000 penalty may be imposed for each day during which the failure to report continues.
 - Penalties must be paid within 30 days of receiving notice of the penalty or interest will be charged.
3. Penalties may also be assessed against Project operators who do not comply with the regulatory requirements specified in the Regulation. If an audit (See

section [7.13, "Audits"](#)) 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 operator would be notified that the cause of the deficiency must be corrected.

If the same deficiency arises in a subsequent Period, a penalty may be assessed. The penalty amount 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 \$1,000.

If the Project operator fails to undertake a measurement or calculation required by the Minister, the operator will be notified and a penalty of no more than \$5,000 assessed for each day the failure continues.

- Penalties must be paid within 30 days of receiving notice of the penalty or interest will be charged.

Operators who submit reports by the report due date; where the report cannot be processed due to minor discrepancies, will be given a 15-day grace period to correct the report before a penalty is issued.

Note:

Penalties levied by the Crown on an OSR Project are not an allowed cost of the OSR Project under OSAC.

Penalty Waivers

Upon written request to the Director, Oil Sands Royalty and Tenure, the Minister may waive a penalty assessed for non-compliance or for late reporting caused by circumstances agreed to be beyond the operator's control.

7.10.1 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
Conventional Oil Sands 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	December 15 th 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 1 st Qtr – May 20 2 nd Qtr – Aug 20 3 rd Qtr – Nov 20 4 th Qtr – April 30 of the following year
CARE – Revenue Workbook	Quarterly – Year to Date and Detailed by Month 1 st Qtr – May 20 2 nd Qtr – Aug 20 3 rd Qtr – Nov 20 4 th Qtr – Feb 20 of the following year
CARE – Project Data Workbook for both In-Situ and Mining (Reserves, Operations, Reservoir, Deposit and Volumetric reporting)	Annually - Year to Date June 30 th of the following year
Western Canadian Select Revenue	Quarterly – Year to Date and Detailed by Month 1 st Qtr – May 20 2 nd Qtr – Aug 20 3 rd Qtr – Nov 20 4 th Qtr – Feb 20 of the following year
CARE – Statement of Approval	<u>For CARE – COSTS & REVENUE Workbooks:</u> 1 st Qtr - May 20 th of the period 2 nd Qtr - Aug 20 ^h of the period 3 rd Qtr - Nov 20 th of the period 4 th Qtr - Feb 20 th of the period (REVENUE Workbook) 4 th Qtr - April 30 th of the following year (COSTS Workbook) <u>For CARE – PROJECT Workbook:</u> Due June 30 th following the Period

7.11 Interest

Oil Sands Royalty Regulation, 2009 (AR 223/2008) section 45

7.11.1 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 Regulations, 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),
- A royalty payment (PSR) from a non-project well event under OSRR'09 section 27(4),
- A refund of excess trucking cost allowance under OSRR'09 section 28(5),
- A pre-payout OSR MRC royalty payment under OSRR'09 section 33(1),
- A post-payout OSR GFE royalty instalment under OSRR'09 section 33(6) and
- A provisional royalty assessment under OSRR'09 section 43(3) or section 43(4)(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 OSR Projects, interest may be payable from the first day of the 7th month of the period until the amount is paid to the Crown, on certain amounts. These amounts are:

- The amount by which royalty payable for the Period exceeds the amount paid by instalments as identified in the EOPS, or
- The amount of an underpayment of royalty identified by a recalculation by the Minister under the Act. (section 38 and 39 of the MMA).

IF

The amount is 10% or more of the aggregate royalty payable to the Crown in respect of the Period.

HOWEVER

- If those amounts arise from an estimate made by the Minister under OSRR'09 section 6(3) or 38(7), or
- If those amounts, net of any amounts resulting from an estimate made by the Minister under OSRR'09 section 6(3) or 38(7), are less than 10% of the aggregate royalty payable to the Crown.

Then interest is not payable from the first day of the 7th month of the Period but only from the first day after the payment due date until the amount is paid to the Crown.

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.

7.11.2 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 well events if 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 instalments 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.
 - If the overpayment is more than 10% of the royalty payable for the Period, interest is computed from the first day of the 7th month of the Period.
 - If the overpayment is less than 10% for the royalty payable for the Period, interest is computed from the due date for the payment of the amount.
- 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 over paid royalty compensation in respect of a month. In this case, interest is computed from the first day of the month following the month in which the overpayment arose.

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:

- 1) In calculating interest for a Period, if the Period includes the effective date of the Project, interest is 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.
- 2) 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.

7.11.3 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/>); navigate to “Our Business,” then to “Oil Sands,” then “Royalties and Ongoing Projects”, then “[Interest Rates](#)”). The interest rate table on this page identifies the interest rates in effect for the non-statute barred Periods.

7.12 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.

[Email:OSReport@gov.ab.ca](mailto:OSReport@gov.ab.ca)

7.13 Audits

Mines and Minerals Act - M17, section 38

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.

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.

7.14 Statutory Requirements and Recalculation

Mines and Minerals Act - M17, section 38

In accordance with section 38 of the Act, 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:

1. On the Minister's initiative in conjunction with an audit or examination; or
2. 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.

7.15 Pre-2009 Inventory and Pre-2009 Transitional Inventory

Oil Sands Royalty Regulation, 1997 (AR 185/97) section 38.1 and 38.2

7.15.1 Transition from OSRR'97 to OSRR'09

Due to changes to the Oil Sands Royalty framework implemented January 1, 2009 (*Oil Sands Royalty Regulation, 2009*), a one-time re-filing of the 2008 EOPS (and 2008-12 MRC reporting form where applicable) was required for Projects with Pre-2009 Inventory volumes. Operators were to identify any oil sands products not yet disposed of, consumed or used as of December 31, 2008. The OSRR'97 was amended to provide for royalty collection on these volumes.

The Department developed Pre-Payout and Post-Payout EOPS, along with a 2008-12 Pre-Payout MRC for Pre-2009 Inventory reporting. These reporting forms are available on the Department's website in Excel format (From the Department's website (<http://www.energy.alberta.ca/>), navigate to "Our Business," then 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 7.8 – “Royalty Reporting Formats and Timing”](#) and Appendix H – “ETS File Naming Conventions” for Form File Naming formats for ETS Submissions. Please note these Excel spreadsheets will be downloaded into a database – therefore no revisions to the form’s format are allowed.

Operators with Pre-2009 Inventory volumes were required to report these volumes and make the corresponding royalty payment no later than April 30, 2010.

As the Pre-2009 Inventory volumes were valued using a simple average of the 2009 monthly unit prices, operators are reminded that amendments to the 2009 Period may trigger amendments to Pre-2009 Inventory reporting. If amendments to 2009 royalty reporting result in changes to the reported unit prices, operators are expected to submit amended reporting required under Section 38 and 39 of the OSRR’09 for Pre-2009 Inventory volumes as well. Amended Pre-2009 Inventory reporting (i.e. 2008 EOPS, 2008-12 MRC) should incorporate the re-calculated simple average unit price that resulted from amendments to 2009 reporting, and adjustments to Royalty payable with corresponding interest (if any) should be remitted at that time.

Note

Under s.38.1 of the OSRR’97, inventory will be valued based on the average of the monthly unit prices calculated for 2009. These unit prices will include the transportation charges for any volumes disposed of in a month in 2009. (As an operator would normally calculate under s.32). This would include any of the transportation charges that would otherwise (under OSRR’97) have been pooled for the December inventories not yet disposed of.

Although there is no more pooling of transportation costs as of December 31, 2008, all transportation costs incurred will be taken into account and will correspond with volumes being disposed of in 2009.

Further details on Pre-2009 Inventory reporting and Royalty Payment are available in Oil Sands Information Bulletins [2009-02](#) and [2009-18](#).

For further assistance related to the Pre-2009 Inventory reporting, contact the “Oil Sands Royalty Account Inquiries” team. (Refer to Appendix G, “Contact Information” or via the OS Reporting Mailbox - OSReport@gov.ab.ca.)

8. Advance Rulings

An advance ruling is a statement by the Department on how it will interpret the applicable legislation, policies and guidelines with respect to a proposed business arrangement or specific allowed costs that relate to an OSR Project.

An operator may request an advance ruling with respect to a discretionary allowed cost as described in section 5 of the OSAC Regulation. (See section [4.2.3.1 "Types of Allowed Costs"](#)) Project owners or operators must submit a written request each time an advance ruling is required.

The issuance of advance rulings is based on full disclosure of all relevant information. Failure to meet this requirement invalidates the ruling.

Once it has issued an advance ruling, the Department complies with the stated terms until such time as the ruling is rescinded. (See section 8.4, "Rescinding an Advance Ruling")

The Department will only issue an advance ruling if the business issue or transaction is one that applies to an actual or proposed OSR project.

8.1 Requesting an Advance Ruling

Requests for advance rulings must be made by Project owners or their designees. They must be submitted in writing and directed to the attention of the Branch Head, Business Design and Evaluation. (See Appendix G, "Contact Information")

The request must be clearly identified as a "request for an advance ruling" and signed by an authorized designee of the Project owner.

8.2 Required Information

A request for advance ruling must include the following information:

- a clear statement of the issue for which the ruling is required
 - This might include an explanation of the purpose of a proposed business arrangement or research project, or a description of the costs of a proposed capital asset.
- a comprehensive analysis of the effect of each relevant fact
- detailed references to pertinent legislation, regulations or authorities
- the applicant's interpretation of the pertinent legislation
- contact information

Additional details may be provided, as appropriate.

8.3 Review and Approval

Requests for advance rulings are processed in the order in which they are received. The Department reviews the submitted material, and in some cases, requests additional information or clarification. In most cases, it issues its ruling within 45 days. More time may be needed for the Department to rule on particularly complex issues.

A request for an advance ruling may be withdrawn at any time before the ruling is issued.

8.4 Rescinding an Advance Ruling

The Department may retroactively revoke an advance ruling if

- the applicant has misrepresented or omitted relevant information in describing the issue
- the business arrangement for which advance ruling was sought is substantially different from what actually transpired

The Department may also revoke an advance ruling if

- the law upon which the ruling was based changes
 - In this situation, the ruling will likely be rescinded as of the date of the change in law, unless the law specifies a different date.

The Department may also revoke an advance ruling if

- government policy changes
 - In this situation, the ruling is rescinded as of the date when the applicant is notified.

9. Appeals and Dispute Resolution

*Oil Sands Royalty Regulation, 1997 (AR 185/97), section 35,
Mines and Minerals Act - M17, sections 38 and 39*

In this chapter, the term “Project owner” should be read to include the Project operator and the authorized representatives of both.

9.1 Issues That May Be Appealed

Mines and Minerals Act - M17, sections 38 and 39

Oil sands Project owners generally have the right to object to calculations or recalculations of

- the Crown’s royalty share, and
- amounts owing with regard to royalty

As set out in Section 38 and 39 of the Act. Matters that are not listed in sections 38 and 39 of the Act are not subject to dispute.

Decisions related to Project approvals and amendments, PNCB, and other matters subject to the discretion of the Minister cannot be appealed.

9.2 Time Limits

Section 38 of the Act provides the authority for the Minister to make the recalculations or additional calculations referred in Section 9.1 – “Issues That May be Appealed”. (*Section 47* of the Act provides for access to the records for audit purposes.) *Section 38* stipulates that—unless there is evidence of fraud or wilful misrepresentation, in which case a recalculation can be made at any time—Department-initiated recalculations must be made within four years of the end of the calendar year in which the mineral that is the subject of the recalculation was recovered or the amount owing applied. If an audit is initiated in the fourth year, the four-year Period is extended by one year.

By the same token, Project owners must exercise their right to request a recalculation within four years of the end of the calendar year in which the original assessment was issued. If a written request by a Project owner is initiated in the fourth year, the four-year Period is extended by one year.

Project owners have 90 days from the time they receive a royalty assessment or audit report in which to initiate an appeal.

Interest and Penalties

When royalty is recalculated under *Section 38* of the Act, by *section 38(5)* the Minister may also make recalculations or additional calculations of interest payable and related penalties.

9.3 The Appeal Process

The first stage in dispute resolution related to calculations or recalculations under Section 38 is informal discussions between the project owner and the Department. If the dispute cannot be resolved informally, the project owner may appeal by filing an objection to the royalty calculation or recalculation. The appeal process for oil sands project owners is similar to that available to holders of conventional oil and gas leases.

Project owners must pay all disputed royalty amounts assessed by the Department before they file an appeal. If their appeal is successful, the appropriate amount will be refunded.

9.4 The Dispute Resolution Process

9.4.1 Requesting an Appeal

To request an appeal, the project owner must submit a written objection to Director of Dispute Resolution, Legal Services. (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:

- the decision under dispute
- how, when and by whom the decision was communicated to the project owner
 - Appeals typically result from decisions arising from a royalty assessment decision or a Departmental audit.
- a description of the project owner's attempts to resolve the dispute with the Department's operational staff
- the reasons for the objection
- evidence that the amount under dispute has been paid to the Crown

The request for appeal must be submitted within 90 days of the Department's issuance of the disputed royalty assessment decision or audit report.

9.4.2 Review by the Director of Dispute Resolution

When an objection is received, the Director of Dispute Resolution (“the Director”) will determine whether or not it is in accordance with the requirements listed above and may accept or reject the objection. He must provide written notice to the applicant whether he has accepted or rejected the objection.

If the Director believes additional information is required for the objection to meet the requirements, the applicant must provide the requested information to the Director within the 90 day Period to initiate an appeal.

If the objection is accepted, the Director will proceed to consider the appeal, by investigating the disputed situation and consulting with the Department and the applicant. He may require additional information from either or both of the parties, which the parties shall provide in a timely fashion. This information may include, without limitation, relevant evidence, legislation, regulations, guidelines, and the parties’ analyses and positions with respect to the objection.

The Director carries out his review of the appeal by investigating the situation and consulting with both the project owner and the Department’s operational staff. Based on this review, he mediates the dispute and proposes a resolution. The Director will propose this resolution within 180 days of the date he received the objection. This timeline may be extended by a further 90 days if both the applicant and the Department agree.

If both the Department and the Project owner accept the proposed resolution, the Director issues a written “**statement of resolution**” to both parties to confirm the agreement.

If the resolution is not accepted by both parties, the Director issues a “**statement of no resolution**” to both parties to document the impasse.

A Note on Timing

In most cases, the Department and the Project owner must accept or reject a resolution proposed by the Director within 180 days of the appeal date. If both parties agree, this time frame may be extended by 90 days.

9.4.3 Requests to Establish a Dispute Resolution Committee

*Oil Sands Royalty Regulation, 1997 (AR 185/97) section 35,
Oil Sands Dispute Resolution Regulation (AR 40/2011) Section 6*

A formal dispute resolution process was established under section 35 of the *Oil Sands Royalty Regulation, 1997* and is available to operators according to the terms of the *Oil Sands Dispute Resolution Regulation*.

In the event that a resolution proposed by the Director is not accepted by both parties, the project owner may request that the dispute be reviewed by a dispute resolution committee (“a Committee”). Only matters which have been subject to appeal (as described in 9.1 - “Issues that May be Appealed” above), and for which a statement of no resolution has been issued by the Director (as described in 9.4.2 above), may be referred to a Committee.

A matter cannot be referred to a Committee unless a statement of no resolution has been issued.

A Committee may be established by a Ministerial Order, issued at the request of the Director. The Director will facilitate the establishment of the committee and assist in coordinating its operations.

A request to establish a Committee must be made to the Director (at the address listed in 9.4.1, above) in writing, by an authorized representative of the project owner, and be received within 90 days of the issuance of a statement of no resolution. The request must include the statement of no resolution, a statement of the dispute the applicant wishes the Committee to review, and the reasons for requesting a review by Committee.

The Director will determine whether the request for review by Committee meets the requirements listed above, and may accept or reject the request. He will provide written notice of his acceptance or rejection to the applicant. If the Director finds the request for review to be incomplete, he may request and accept from the applicant any additional information required. This information must be provided within the 90 day Period allowed to request the establishment of a Committee after the issuance of the statement of no resolution.

Where a project owner has requested that a matter go to a Committee, the Minister will not make a decision on the issue in dispute until the Minister has received and considered the recommendations of the Committee.

9.4.3.1 Selecting a Committee

Oil Sands Dispute Resolution Regulation (AR 40/2011) – section 8

If the request is accepted, the Director will require the Department and the applicant to each identify three individuals who have consented to participate as members of the Committee. The individuals identified cannot be employees of the Department or the applicant, or an affiliate of the applicant. The Department and applicant must also inform the Director of their preferred number of Committee members. This information must be provided within 30 days of the acceptance of the request.

The Director will provide this information to the Minister, and may make recommendations to the Minister on the size and composition of the Committee.

The Minister will determine the size and composition of the Committee. The Minister may choose the members from those names submitted by the Department and applicant, or request that the parties identify additional candidates for consideration. The Minister will establish the Committee within 90 days of the receipt of the information from the Director, unless the Minister determines additional time is required. The Committee will be appointed in accordance with *section 7* of the *Government Organization Act*. Committee members will receive honoraria as determined by the Minister and will be required to take an oath of confidentiality.

9.4.3.2 The Role of the Committee

Oil Sands Dispute Resolution Regulation (AR 40/2011) section 9 and 10

The function of the Committee is to hear the merits of the request, and to provide the Minister with written recommendations, and the reasons for those recommendations, for the Minister's consideration.

The Committee may carry out research and conduct such hearings as necessary to carry out its function. The Ministerial Order establishing a Committee may set out the processes to be followed by the Committee – i.e. whether hearings will be oral or written, and whether the Committee may retain outside experts, etc.

Once the Committee concludes its work, it will prepare a written recommendation for the Minister's review. The recommendation must be supported by the committee's reasons for its proposal and any supporting documentation the Minister may request. The recommendations must be provided to the Minister within 120 days of the Committee's appointment, unless the Minister agrees to an extension.

9.4.3.3 The Minister's Decision

Oil Sands Dispute Resolution Regulation (AR 40/2011) section 10

On receiving the Committee's report, the Minister will review and consider its recommendations and make a decision with regard to the matter in dispute.

9.4.3.4 Notification and Publication

Once the Minister has considered the Committee's recommendations and the Minister has made a decision on the matter in dispute, the Director will notify the Department and the Project owner of the Minister's decision. Both parties will then cooperate to implement the Minister's decision.

If a Ministerial decision based on the recommendation of a Committee affects the interpretation of an oil sands regulation or guideline, which may affect other oil sands project owners, the Department will inform all interested stakeholders via an Information Letter or some other appropriate method.

9.4.3.5 Costs

Costs associated with or incurred by a Committee will be shared equally by the project owner and the Department.

Committee costs may include honoraria for members.

Committee costs associated with dispute resolution are not an allowed cost of an oil sands royalty project.

9.5 Informal Mediation of Project PNCB

The Director may also perform an informal review and mediation of a Project's PNCB and pre-payout costs upon the request of the project owner.

Requests for this service should be addressed, in writing, to the Director within 90 days of the receipt of the decision or audit report of which review is sought. The process outlined in section 9.4.1 "Requesting an Appeal", should be followed, and the project owner must pay all disputed royalty amounts assessed by the Department before they file a request for an informal review.

This process is an informal attempt to resolve an issue between a Project operator and the Department and will not involve a Committee or result in recommendations to the Minister. If the matter relates to an issue of the Crown's royalty share or a calculation or recalculation of royalty, it can still be disputed through the process outlined in ["9.3 – The Appeal Process"](#).