Oil Sands - UNITAR (7th) Alberta Department of Energy

UNITAR international conference on heavy crude and tar sands, held October 27 – 31, 1998, 7th : proceedings : heavy oil - a major energy source for the 21st century

Alberta's Oil Sands: Update on the Generic Royalty Regime
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Note: This paper was presented in October 1998, therefore key issues and options are included rather than the definitive positions that will be used for the new regulation. Furthermore, any positions, ideas or options regarding the new oil sands royalty system included in this paper is subject to change. It was originally produced as web content, in 2017 it was converted to a document for Open Government.

Abstract

This paper provides an overview of the Province of Alberta's new oil sands royalty regime. On September 24, 1997, the Alberta Cabinet completed enactment of a generic royalty regime that will ultimately replace the custom-tailored Crown Agreements. This regime will apply to new investment in developing Alberta's oil sands and expansion of existing projects.

The locations affected by the regime include the Athabasca, Peace River and Cold Lake Oil Sands Areas which underlie an area of 77,000 square kilometers of the province, and contain about 1.7 trillion barrels of bitumen in-place. The paper will discuss the development, objectives, and features of the regime including a discussion of the Act amendments, and the regulation and business rules.

Introduction

The Alberta Government recognizes that Alberta's oil sands are playing a large and increasing role in maintaining the province's position as the leading producer of liquid fuels in Canada. The province's current and future prosperity is linked to a great extent to the oil sands, and production of bitumen and synthetic crude oil continues to rise. Oil sands production is expected to continue to grow and could reach 1.2 million barrels over the next eight years. The Alberta Chamber of Resources estimates that with an investment of $21 to $25 billion, oil sands production could triple in the next 25 years. **Tables 1** and **2** presents some recent statistics for oil sands production and royalties.

The Department of Energy (the "Department") is responsible for preparing the province's oil sands policies and regulations, including those for leases and royalties. It also manages the funding of the government's oil sands research and development programs.

The Department has taken considerable steps to make oil sands development attractive now, and one example is the generic oil sands royalty regime. The drivers for this new generic royalty regime are that the oil sands sector has matured; that industry wants royalty certainty for business planning; and that government wants to stop the steady erosion from the benchmark terms of the original Crown Agreements as each new developer negotiated slightly better terms to "make their project go." The new generic regime is also more administratively simple in the face of the large number of possible future projects and project expansions.

The generic royalty regime is designed to support the major investment needed to develop the oil sands resource. The new system recognizes the challenges faced by oil sands developments, with a smaller royalty share for the government until developers have recovered their costs. This is an example of the government's new approach to development; instead of participating directly, it is establishing a framework that should encourage new oil sands projects, which means more jobs and a stronger Alberta economy. The regime is the result of several years of collaboration between industry and government. **Table 3** presents a chronology of the development of the generic oil sands royalty regime.

The Crown owns the oil sands resource, and both the federal and provincial governments have taxation powers. To avoid duplication of the tax collection system, the federal government administers the income tax system for itself and the province. The federal and provincial governments have collaborated to improve the tax system to ensure that federal changes are mirrored provincially. The federal government has agreed to monitor the success of Alberta's new "economic unit" approach to defining an oil sands project for royalty purposes, and if it is successful has agreed to consider changes conforming to this new approach for tax purposes.

The Generic Oil Sands Royalty Regime

Objectives of the New Regime

The National Task Force on Oil Sands Strategies released a comprehensive report (spring 1995) that outlined a detailed list of recommendations for the oil sands industry. The Task Force proposed a generic oil sands royalty system based on a specified percentage of net project revenues after all costs are recovered. This Task Force proposal reflected the type of royalty system already in place through various individual oil sands Crown Agreements (i.e., Cold Lake, Syncrude, and Suncor). These Agreements provided a foundation for the Task Force's recommendations and for the Government's new generic royalty system.

The objectives of the new regime are as follows:

- Accelerate the development of the oil sands while ensuring a fair return to the resource owners – Albertans;
- Facilitate development of the oil sands by private sector companies. Development must occur because businesses expect to make a reasonable profit from the venture. Alberta will not directly participate through grants, loans, loan guarantees, or any other "special" deals;
- Ensure that oil sands development is generally competitive with other petroleum development opportunities around the world; and
- Create a standard set of royalty terms for new projects to create a clear, consistent, and stable system.

The New Generic Regime

The generic royalty regime developed for oil sands is administered by the Department under the Mines and Minerals Act.

The first part of the generic oil sands royalty regime are the core rates, which are embedded in the Mines and Minerals Act. The second part of the regime are the principal administrative provisions, such as cost schedules and revenue definitions, which are included in the 1997 Oil Sand Royalty Regulation. Business rules, developed jointly by the Department and industry, are the third component of the regime. The business rules ensure administration rules are efficient and effective.

The new generic royalty regime is prospective in nature, but Alberta will honor the terms of the past Crown Agreements, and is working towards melding the two royalty regimes for expansions of existing projects. The melding of the two regimes will be based on production from the Crown Agreement portion of the project and from the expansion. The objectives and principles for the transition from Crown Agreements to the generic royalty regime were approved by Alberta's Standing Policy in February of 1996, and are outlined in **Table 4.**

The generic oil sands royalty regime applies to new investment in developing Alberta's oil sands, and the expansion of existing projects.
The basic elements of the regime include:

- A minimum 1% royalty payable on all production;
- Royalty on production equivalent to 25% of net project revenues after the developer has recovered all project costs, including research and development costs, and a return allowance (after "payout");
- The return allowance is set at the Government of Canada Long-Term Bond Rate;
- All projects cash costs including capital, operating, and research and development are 100% deductible in the year incurred;
- No gross up of operating and capital costs; and
- No gas royalty waivers.

New Generic Royalty Regime Vs Gross Revenue (Production Based) Royalty Regime

The main part of the oil sands royalty is based on 25% of net revenues of the project after payout. Through this feature Alberta is sharing risk, and is participating with the developer whose return is linked to the project's success. Only when a developer's cumulative project revenues exceed cumulative costs, including a return on investment equal to the long-term bond rate, does Alberta participate in a significant royalty.

This approach was chosen due to the high cost, long lead time, and the associated high risk nature of oil sands investment. Production-based royalties, such as those used for conventional oil and gas, are less sensitive to project profitability. Because the oil sands face higher barriers to development than many other types of petroleum (less valuable product, higher technological risk, higher capital costs, and higher operating costs, etc.) the additional burden of a significant production based royalty was determined to be inappropriate.

The Generic Oil Sands Royalty Regime vs. Current Crown Agreements

Under the old royalty system, individual Crown Agreements were negotiated with each oil sands project. For example, Suncor, Syncrude, and Imperial Cold Lake are all subject to their own Crown Agreement. The old Crown Agreement system made sense in the formative stages of the sector, when each developer felt their project was different, and when each Crown Agreement was built on the experience of previous Crown Agreements. Now that the industry has moved into a more mature stage, the generic regime makes more sense. The government now has a good knowledge and experience base with respect to royalties and taxes, and the past Crown Agreements provide a good basis for a workable generic royalty regime.

The main purpose of the generic oil sands royalty regime is to provide a level playing field – common rules that apply equally to all developers. **Tables 5** and **6** illustrate the components of generic royalty regime, and the features that have changed from the current Crown Agreements.

Implementing Alberta's New Generic Royalty Regime

During the past two years a team within the Department reviewed the existing Crown Agreement royalty system to identify those elements which could be retained and those which would require modification to reflect new development practices and the new royalty structure. The Department also carried out formal and informal consultations with current and prospective oil sands developers throughout this period.

The key elements in implementing the new regime include:

- The definition of an oil sands project;
- Costs and revenues included in the royalty calculation; and
- The return allowance.

Definition of an Oil Sand Project

The generic oil sands royalty regime determines and collects royalty on a project basis. The project-based regime is built on the concept of a project being developed as an *economic unit*, and should therefore be generally consistent and compatible with the project owners' drive for a project design that allows for efficient and effective economic and business decision making. Where both resource recovery and processing facilities are developed, the developer can seek to include the processing facilities in the project.

Project proponents should be able to demonstrate that there are operational synergies and economies of scale that realize economic efficiencies and cost savings compared with the development of separated, individual stand-alone production and processing facilities.

Economic Unit

The economic unit approach allows project design and development to be driven by intrinsic economics – unaffected by the royalty provisions. Therefore, in reviewing project applications, the Department will be satisfying itself that the proposed project boundaries and facilities included are justified for business and economic reasons. As the royalty participant in a project, the Department will be looking for project boundaries that will maximize the present value of future cash flows to the project owners and the Crown. If the Department feels that an aspect of the owner's proposed project definition does not materially benefit the project's profitability, including royalty share, but instead results in a shift of the Crown's share of project revenue to the project's equity owners; the province will not approve that project application until it is amended to protect the province's interest.

Facilities to be Included

The economic unit may include all operations associated with the recovery of leased substances, processing these substances into oil sands products and transporting them to the Project's boundary. For royalty determination purposes, the directly related expenditures for both recovery and processing can be deducted as allowable costs. In return for allowing the deduction of such costs for the purposes of determining royalty owed to the Crown, the Crown is entitled to include all revenue arising from those expenditures in the determination of the 25% net revenue based royalty. For example, if a project's approved definition includes an upgrader, all cost directly related to that upgrader may be deducted in determining the royalty payable, but all upgrader related revenue must also be included. Revenue arising from leased substances will be included in the determination as revenue. Other project revenue is generally treated as a negative cost.

Figure 1 illustrates three basic scenarios of how projects can be defined, as well as the resultant gross revenue for each scenario for the purposes of royalty determination.

Value-added processing is encouraged where it is consistent with intrinsic economic investment objectives. Pipelines and flowlines will be considered for inclusion in a project where they transmit project substances from one part of the project to another, or where there is an economic return for both the project and the Crown from having the project boundary at the pipeline outlet rather than the inlet.

In reviewing the considerations required by the Regulation to determine Project eligibility, the Department will, among other things, determine to its satisfaction:

- That the proposed Project has Alberta Energy and Utilities Board (EUB) regulatory approval,
- Whether the project is operated under common management, and
- Whether all components of the proposed project lie within a 50 kilometer radius and will be operationally integrated.

EUB Regulatory Approval

All proposed components of a project must be approved as a scheme(s) or facility by the EUB. For royalty purposes the "project" can include multiple EUB production approvals. Wells that have been drilled under an EUB single well license will only be eligible for inclusion if they were drilled on land that is included in the scheme approval(s). *Note: The EUB the regulatory board for Alberta later became the Energy Resources Conservation Board (ERCB) and the Alberta Energy Regulator (AER).*

Common Management

Operations within a project are under common management and are to be treated as one common business unit for royalty determination purposes.

*S*creening Tests: Within 50 kilometers and Integrated Operationally

All components of the proposed project lie within 50 kilometers from one side of the unit to the opposing side of the unit. This distance is equivalent to approximately five townships, and given current technology, is a reasonable proxy for the distance that:

- Steam or other injection fluids can be economically distributed to remote injection wells; and
- Dirty bitumen can be piped or trucked to cleaning facilities.

Upgraders and pipelines connecting an upgrader to the rest of a project are not subject to the 50 kilometer guideline.

Proposed projects with components that lie beyond the 50 kilometer guideline, other than those associated with upgrading, will only be considered for inclusion in the project when the applicant can clearly display that those components provide significant economic and operational synergy, and can demonstrate that those components are or will be integrated operationally with the rest of the project. Where an applicant for a project with components that do no meet the 50 kilometer guideline cannot demonstrate to the Department's satisfaction that the components will be operationally integrated, and thus provide economic synergies, the Crown may require separated projects for royalty purposes.

Overlap with Other Projects

Where facilities in a proposed Project are co-owned and shared with another project, each project must, on its initial application, make a determination of the percent allocation of the shared facilities to be assigned to each project for royalty purposes. Where the common ownership is for processing facilities, the allocation would be proportional to each project's percentage ownership of the processing facility. This allocation will determine the relevant allowable cost/revenue share for royalty determination purposes.

Where processing facilities to upgrade crude bitumen into an oil sands product are included within a project, and where those facilities are used to process bitumen from other than the project, the costs associated with the upgrading will be included for royalty determination for this project, as will the revenues or deemed revenues.

Project Expansions

One of the goals of the new oil sands royalty regime is to facilitate staged development, whereby projects can grow over time by increments that attain economies while keeping the incremental investment outlays as small as necessary. Project expansions and growth are accommodated within the broad framework of adhering to the economic unit guidelines. Beyond a certain size, there is an expectation that potential diseconomies would arise as operations span extended geographic distances. Where such diseconomies occur, projects would have to be developed on a separated, stand alone basis until it can be demonstrated that technology has advanced to the point where the diseconomies have been overcome. At that time, the project may apply to the Department to combine the projects.

Projects that start only as resource recovery facilities can be expanded to encompass processing facilities at a later date. However, once a project is established to include processing facilities, these facilities cannot be disaggregated from the project to eliminate their inclusion for royalty determination purposes.

Expanding beyond 50 kilometers

A Project may expand beyond the prescribed geographic boundary if it meets one of three conditions:

- It must be able to demonstrate related economic operating efficiencies to justify such an expansion;
- It must have contiguous leases that extend beyond the boundary, with leases not separated by more than a distance of approximately 5 kilometers; or
- It must share common ownership of processing facilities to upgrade the crude bitumen into an oil sands product.

Cost and Revenues Included in the Royalty Calculation

Determining project revenue is necessary for the 25% net revenue based royalty portion of the new regime. Project revenue depends on the definition of the project itself, as discussed in the preceding section, as well as the substances that are sold and the calculation of the unit price.

Determining allowable project costs is necessary in order to calculate when the project reaches payout. After payout, the project pays the greater of the 1% minimum royalty or the 25% net revenue based royalty. As with project revenue, project cost relate to the definition of the project itself.

In general, an allowed cost must satisfy the following criteria:

- It is directly attributable to the Project,
- It is reasonable in relation to the circumstances under which it is incurred;
- It is incurred by, or on behalf of the owners of the Project;
- It is incurred on, or after the effective date of the Project; and
- It is incurred to recover, purchase, process, transport, and market oil sands product, or to conduct or provide field office or administrative services.

Approved Research and Development costs are allowable if they are directly attributable to the project.

The Return Allowance

The return allowance, set at the Canadian Long Term Bond Rate, is a key feature of the generic regime because it is a significant factor in determining when a project moves from the minimum 1% royalty to the greater of that royalty or the 25% net revenue based royalty. Developers will only invest in oil sands projects if they expect to earn at least their risk adjusted cost of capital over time. Due to the risks of oil sands development, the time required for a developer to achieve this objective can be relatively long – potentially 6 to 8 years. If the return allowance was set at the developer's risk adjusted cost of capital, which would be substantially higher than the bond rate, projects could take a long time to reach payout, and therefore extend the day they begin to pay more royalty.

Alberta's oil sands generic royalty regime is a variant of the widely accepted "resource rent royalty" (RRR) approach. Under the RRR approach, rent is defined as the difference between the costs of producing output for the highest cost oil sands project (zero rent) and the value of output on any other project. The RRR approach extracts this rent in a way that is as revenue neutral as possible, allowing the developer to recover the costs of investment (including a return on investment to account for risk). The oil sands generic royalty regime sets the return allowance at the Canadian Long Term Bond Rate, which is below the developers cost of capital, so that Alberta can begin to receive royalties earlier than if it had been set at the developers cost of capital. Alberta has also included the 1% minimum royalty in the pre-payout period so that it can participate earlier in the rent sharing. In return for the earlier rent sharing, the Alberta government has set the economic rent in the after payout period below the 100% level, at 25%. This lower economic rent also should provide producers with an incentive to reduce costs in the after payout period, thereby increasing returns from the project for both the investor and the Crown.

Past experience with Crown Agreements has shown that this type of regime does not encourage developers to spend money for the purpose of avoiding payout. For example, a developer does not have an economic incentive to spend $4 in order to save $1.

Effects of Implementing the Generic Oil Sands Royalty Regime

How does this regime compare to other regimes around the world?

It is difficult to compare the generic regime to regimes for other resources because the oil sands are unique. However, based on the Department's analysis, the generic regime provides an appropriate fiscal system for oil sands development, while still providing a sufficient return to Alberta from the oil sands resource.

In combination with federal and provincial income taxes, after project payout, a 25% net revenue royalty results in the developer receiving marginal project income of 42%, with the balance of 58% going to the federal and provincial governments through royalties and corporate income taxes. Developers also pay other taxes, such as municipal property taxes.

What are the economic benefits for Albertans?

The expected increase in oil sands investments is due to a combination of a stable, consistent, and clear fiscal regime (tax and royalty), improved technology, lower operating costs, and strong market demand. Since the announcement of the generic oil sands royalty regime in 1995, industry has already announced plans to invest an additional $19 billion in the oil sands over the next eight years. These recently announced investments represent a potential of over 1.2 million barrels/day of oil sands production. The proposed oil sands facilities from these investments would create thousands of permanent jobs in Alberta.

What is the expected effect on royalties?

The royalties for the 1995/96 and 1996/97 fiscal years, and the expected royalties for the 1997/98 and 1998/99 fiscal years are provided in **Table 2**. Note that oil sands royalty revenues are expected to decrease in the near future, from $194 million in 1997/98 to about $50 million in 1998/99.

The expected short-term decline in royalties is a result of several factors, including:

- Immediate deductibility of massive reinvestment in the Syncrude and Suncor projects;
- Higher levels of capital spending in Imperial's Cold Lake project;
- Lower expected prices for bitumen and synthetic crude oil; and
- Current royalty revenues result from the exceptional 1996/97 year, which had high prices and did not face the large new investments; and the decrease in royalties represents a return to levels closer to the historic average.

Oil sands royalties can be expected to increase significantly once higher production levels are reached, and project developers have earned back their invested capital. Generally, the petroleum industry only invests in projects that can be expected to pay back their invested capital in less than eight years. Therefore, depending on oil prices and production, new projects can be expected to begin paying royalties of 25% on net project revenue within six to eight years of operation.

The large amount of oil sands investment is, in part, a result of new technological advances that hold promise for cost reductions. The oil sands generic royalty regime is the Departments attempt to encourage investment by requiring lower royalties in the years immediately following the start of new projects and project expansions; and higher royalties when the new project or expansion reaches payout. This royalty regime design is intended to provide an incentive for the capital investments necessary for the development of the oil sands, while still allowing appropriate royalties to be collected over time, albeit the bulk of royalties will be shifted to future years.

Changes to Income Tax Regulation

The rules governing taxation of oil sands projects are found in the Federal Income Tax Act. For Capital Cost Allowance (CCA) purposes, all oil sands assets are included in Class 41 of the Federal Income Tax Act.

The Federal Budget of 1996 announced changes to the federal income tax policy. The key changes are:

- Since in situ and mining projects produce essentially the same product, all oil sands investments (in situ and mining) are now treated the same for taxation purposes.
- All investments (new projects and expansions of existing projects) are treated the same for taxation purposes, with the exception that expansions which increase gross revenue by 5% or less are treated as sustaining investment.

CONCLUSION

The Government of Alberta has worked with industry for several decades to unlock the vast petroleum resource contained in Alberta's oil sands, and to encourage its development by the private sector. Some of the direct benefit of this sustained effort has already been realized through royalty and tax revenues arising from existing oil sands projects. There has also been substantial indirect benefits to the Alberta economy from oil sands development that arises from the direct and indirect employment income and wealth created by the oil sands projects moving through the various service and supply sectors. The economic benefits from the oil sands can be expected to continue as industry proceeds with the planned $19 billion of investment made public by industry since the Generic Oil Sands Royalty Regime was announced in late 1995.

References

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Masson, Richard, and Bryan Remillard. *Alberta's New Oil Sands Royalty System*, Edmonton: Alberta Department of Energy, 1996.

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Tables and Figures

Table 1: Recent Oil Sands Production Statistics by Calendar Year

2,073,000 barrels/day	1997 (estimated) total Canadian crude oil and equivalent production
 286,400 barrels/day 14% 279,500 barrels/day 3%	Synthetic crude oil production (Crown and freehold): Alberta, 1997(estimated) Percentage of 1997 Canadian total crude oil and equivalent production Alberta, 1996 Percentage change (Alberta – 1996 to 1997)
 42,0000 barrels/day 12% 165,600 barrels/day 45%	Bitumen production (Crown and freehold): Alberta, 1997 (estimated) Percentage of 1997 Canadian total crude oil and equivalent production. Alberta, 1996 Percentage change (Alberta – 1996 to 1997)

Table 2: Recent Oil Sands Production and Royalty Statistics by Fiscal Year

1,289,000 barrels/day	1996/97 Alberta total crude oil and equivalent production
277,400 barrels/day 22%	Synthetic crude oil production (Crown): Alberta, 1996/97 Percentage of 1996/97 Alberta total crude oil and equivalent production
162,200 barrels/day 13%	Bitumen (Crown): Alberta, 1996/97 Percentage of 1996/97 Alberta total crude oil and equivalent production
$312 million $512 million $194 million $50 million	Oil sands royalties generated: 1995/96 1996/97 Expected oil sands royalties: 1997/98 1998/99

Table 3: Chronology of the Development of the Generic Oil Sands Royalty Regime

1993	Formation of the joint industry-government National Task Force on Oil Sands Strategies
May 1995	Recommendations of National Task Force on Oil Sands Strategies
September 6, 1995	Standing Policy Committee approval of generic oil sands royalty regime
October 31, 1995	Alberta Cabinet approval of generic oil sands royalty regime
November 30, 1995	Premier Klein's announcement that a new generic oil sands royalty regime (25% royalty rate after developer's cost plus return allowance have been recovered, subject to a minimum royalty of 1% of gross revenue) will apply to new projects
February 1996	Standing Policy Committee approves application of generic terms to new investment in expansions of existing projects
March 6, 1996	Federal Budget creates a uniform tax policy for all oil sands projects, regardless of the method of extraction. Province mirrors the federal

	changes in the provincial tax regime
June 1996	Declaration of Opportunity in Ft. McMurray. Attendance included the Prime Minister and the Alberta Energy Minister as well as many other prominent industry and government representatives
June 12 1996	Approval by Order in Council of transition terms for Syncrude and Suncor Projects designed to blend the existing royalty terms for existing projects with generic terms for production resulting from incremental investment
February 12, 1997	Minister of Energy signed Transition Agreement for Syncrude Project
March 5, 1997	Minister of Energy signed Transition Agreement for Suncor Project
May 29, 1997	Legislature approval of amendments to establish core provisions of the generic oils sands royalty regime in the Mines and Minerals Act
September 24, 1997	Alberta Cabinet Approval of generic oil sands royalty regulation.

Table 4: Objectives and Principles for the Transition from Crown Agreements to the Generic Royalty Regime

Transition Objectives
Standardize the royalty for oil sands projects – at the end of the transition period all oil sands developers should be under a single royalty regime. Treat all developers fairly – flexible transition arrangements should ensure that royalties from existing operations are not unduly eroded while at the same time allowing new investments to proceed under the generic oil sands royalty regime.
Transition Principles
Any transition to the generic royalty regime should be predicated upon some significant change in the project, such as a significant expansion or moving to a new lease. Any transition should be essentially revenue neutral in the short-term – not in every year, but over some period; the transition should help stabilize the annual royalty from each project. Any transition should provide a royalty regime which will allow investment to proceed. Any transition should not significantly bias investment or production decisions. Any transition should place existing players on a level playing field with other new investors on a go-forward basis (i.e., the transition arrangement should see the developer effectively paying the generic royalty rate on new developments, although royalties paid may also reflect existing terms on base production). Royalty on new developments should be based on the value of the first marketed product. Any transition should be administratively manageable, and easily auditable.

Table 5: Components That Establish the Generic Royalty Regime

Mines and Minerals Act, section 125.1	Core rates defining the revenue minus cost royalty formula. The following rates are embedded in Legislation (Bill 12) passed in May 1997: The 1% minimum royalty rate, The 25% net revenue based royalty rate after project payout, and The long-term bond return allowance rate.
Oil Sands Royalty Regulation, 1997	The Regulation contains the principal administrative provisions, cost schedules, and revenue definitions. The Alberta Cabinet enacted the Regulation in September 24, 1997.
Business Rules	Business rules are being developed jointly by the Department and Industry to ensure administrative rules are efficient and effective.

Table #6: Features That Have Changed from Current Crown Agreements

Feature	Generic Regime	Crown Agreements
Royalty Rates: Minimum: Maximum:	1% minimum royalty. 25% net revenues based royalty.	0-5% minimum royalties. 25-50% net revenue based royalty. (Note: deemed net profit definition varies).
Allowable Costs:	All costs allowed immediately. No gas royalty waivers. No gross-ups of capital and operating costs	Some costs allowed immediately. Some gas royalty waivers. Gross-ups of capital and operating costs,

FIGURES

Figure 1: Project Types and the Resultant Treatment of Gross Revenue for Royalty Purposes

The following three diagrams outline some basic project scenarios and show how the gross revenue from each scenario will be treated for royalty purposes. Royalties will be based on the gross revenue as follows:

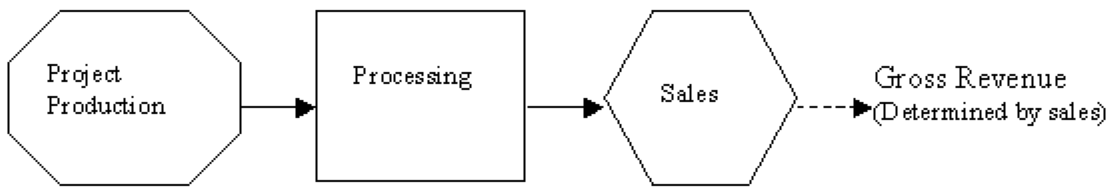
- The pre-payout period – royalties will be the minimum 1% of production.
- After the payout period – royalties will be the greater of the minimum 1% of production, or production equivalent to 25% of net revenue (which is the gross revenue less allowed costs).

Note that each project can have single ownership or joint ownership. In the case of joint ownership, the project is still considered a single economic unit for the purposes of royalty determination. The project operator will be responsible for the royalty payment, and the owners will determine among themselves the sharing of the obligations for payment.

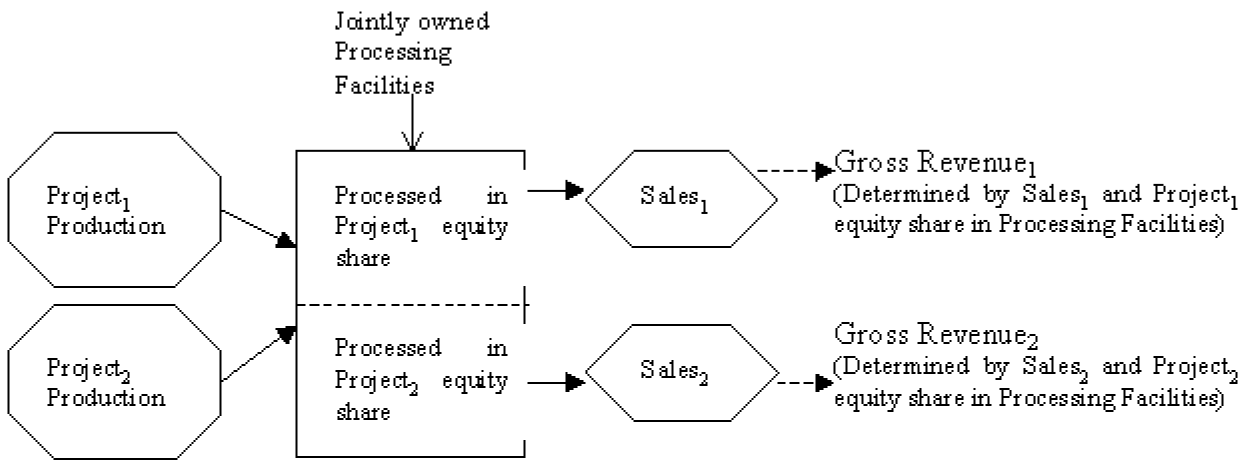
These diagrams illustrate how gross revenue will be treated for royalty purposes for bitumen and/or synthetic crude oil projects.

- For a Bitumen project, the production is dirty bitumen, processing is cleaning of the bitumen, and the sales is the clean bitumen.
- For a synthetic crude project, the production is the clean bitumen, processing is the upgrading, and the sales is the synthetic crude.
- A third possibility is where production is dirty bitumen, processing is both bitumen cleaning and upgrading (possibly in two different plants connected by a pipeline), and sales is synthetic crude.

1. **The Stand Alone Project**



2. **Co-ownership of Processing**



3. **Custom Processing**