5. Specific Cost Allocation Rules

5.1 Solution Gas and Fuel Gas

Many oil sands 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 natural gas that is dissolved in crude bitumen under initial reservoir conditions. 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 oil sands royalty 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 – assuming also that there is no sale of the solution gas. In some cases, the solution gas produced in association with oil sands is used as fuel for project facilities; in other cases, the solution gas is sold and becomes subject to royalty payable under the Natural Gas Royalty Regulation, 2002.

Note

The rules governing the treatment of capital and operating costs of equipment in oil sands royalty projects used to gather, compress or treat solution gas that is sold is the subject of the Solution Gas and Off Lease Fuel Gas Task Force operating under the Oil Sands Royalty Steering Committee. Resolution of the issue has been approved by the Steering Committee and is contingent on a Regulation change. Upon implementation of the Regulation change these guidelines will be updated to reflect the business rules as approved by the Department.

5.2 Pipeline Services

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 7.3(1) to 7.3(7)

Pipelines for transporting bitumen (or blended bitumen) to market—that is, from a royalty calculation point to the point of disposition—are called non-basic***** pipelines because the service they provide is not needed for the production of clean crude bitumen—the minimum output required of any oil sands royalty project (see *section 21(4)* of the Regulation).

Under the terms of the Regulation, non-basic pipelines cannot be included as part of an oil sands royalty project description. However, charges for the use of such pipelines can be deducted from the unit price of the oil sands product. (see 5.2.1, "Calculating Allowed Costs for Non-Basic Pipeline Services") The total charge that can be claimed is the sum of the operating costs plus the capital costs per m^3 of capacity. Both costs are based on the portion of pipeline throughput that pertains to the project.

In some cases, project owners may also deduct a portion of the cost of oil purchased to "fill" the pipeline. (see 5.2.2, "Line Fill Costs")

5.2.1 Calculating Allowed Costs for Non-Basic Pipeline Services

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

- If the pipeline is owned by the oil sands royalty project owner or by an affiliate, and if the Minister can establish the fair market value of the pipeline service, the allowed cost is the *lesser of* the amount charged to the project or fair market value.
- If the Minister cannot establish fair market value, 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.

For a definition of fair market value, see 9.1.4, "Fair Market Value".

For details about cost-of-service calculations for pipelines, see 5.2.1.2 "Allowed Costs Based on Cost-of Service Calculations".

5.2.1.1 Allowed Cost Based on Fair Market Value

The fair market value of non-basic pipeline services can be approximated by using a regulated tariff charge for pipeline services.

When there is no regulated tariff, a published tariff charged by the pipeline owner may be used —if the following rules apply:

- The tariff is 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 pipeline tariffs are not available, or when no comparable service exists, the fair market value 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.

5.2.1.2 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 fair market value 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 cost of service calculation methodology is described below:

- The cost-of-service 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).

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

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.

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 and corporate income tax rate may be revisited at the Minister's discretion, or when there are significant market or tax changes.

Additional cost rules apply to

- sales of pipelines (see 5.2.3 "Cost Rules for Sales of Pipelines")
- pipeline overcapacity (see 5.2.4 "Cost Rules for Pipeline Overcapacity")
- capital additions to pipelines (see 5.2.5 "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:

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

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 Non-Arms Length (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.

5.2.2 Line Fill Costs

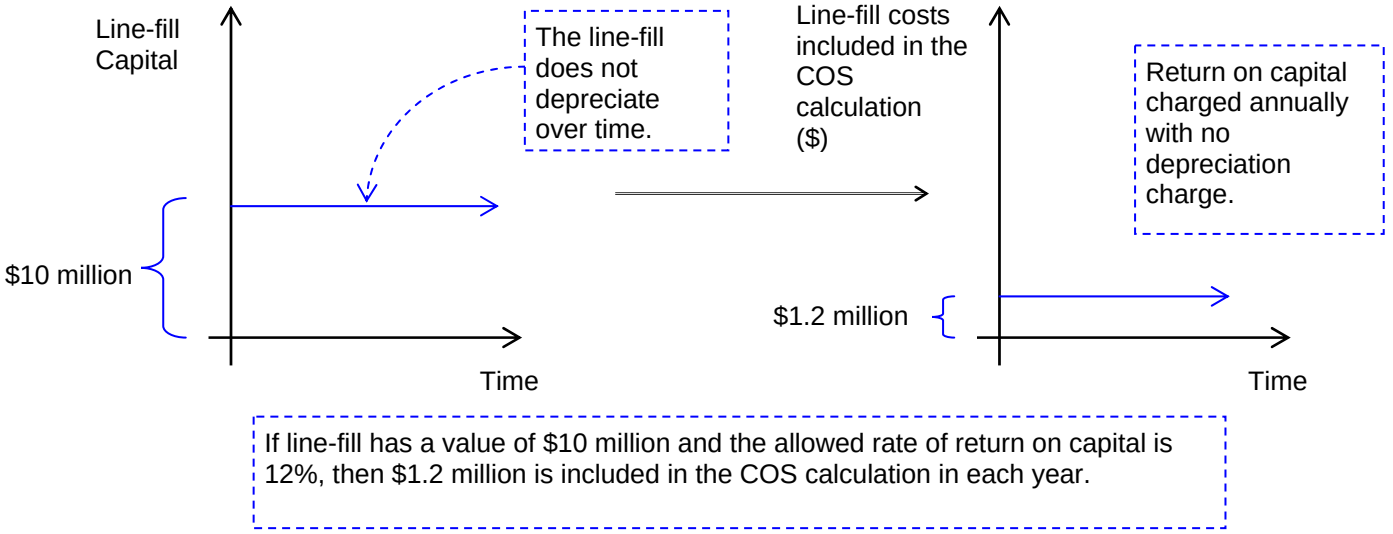
In addition to the cost of service, project owners may deduct a portion of the cost of the oil volumes purchased to "fill" the pipeline. The line fill volume is valued at the price at which it was acquired. Its return rate (RORC) is the same as the return rate allowed for the cost-of-service calculation. 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 cost of service 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. The return rate (RORC) is calculated as follows:

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

- Revaluations of line fill costs are not allowed.

Figure 6: Calculating line fill costs



5.2.3 Cost Rules for Sales of Pipelines

If a project-owned pipeline is sold or transferred, and if the sale price is higher than the pipeline's undepreciated capital cost, a new third-party toll must be established. The new pipeline toll is adjusted to reflect the pipeline's sale price. This ensures that the Crown does not pay for capital costs it already paid for through pre-sale cost-of-service depreciation.

The new, post-sale pipeline toll (used as a unit price deduction) is adjusted by the difference between the sale price and the undepreciated value of the pipeline. This amount is called the sale price premium. The adjustment factor is the flat-rate, dollars-per-volume toll that makes the pipeline's net present value (NPV)—given the expected pipeline throughput—equal to the sales price premium over the remaining expected life of the oil sands project.

The adjustment factor is calculated at the time of the pipeline sale and applies for the life of the project. Corrections can be made if the Department finds that estimates made with regard to project life or pipeline throughput were inaccurate.

5.2.3.1.1 Calculating the Adjustment Factor

1. The original pipeline owner determines
   - the sale price premium (sale price minus the pipeline's undepreciated capital at the time of the sale)
   - the remaining expected life of the oil sands project at the time of the sale
   - the estimated throughput for the pipeline's remaining expected life
2. The Department of Energy reviews and approves these determinations.
3. The pipeline owner calculates the toll adjustment factor that will be used to calculate the unit price.

$$\text{Adjustment factor } (\$/m^3) = \frac{\text{Estimated annual value of the sale price premium}}{\text{Estimated annual throughput}}$$

For example

Assumptions:

- A NAL non-basic pipeline subject to a COS calculation is sold to an unaffiliated 3rd party for $27.5 million;
- The pipeline's undepreciated capital at the time of the sale is $22.5 million;
- The sale is made in year 15 of the oil sands project, which has an expected life of 40 years;
- Pipeline throughput is 55 million barrels per year;
- The 3rd party discount rate is 12.92%; and
- The 3rd party toll is $0.200/barrel.

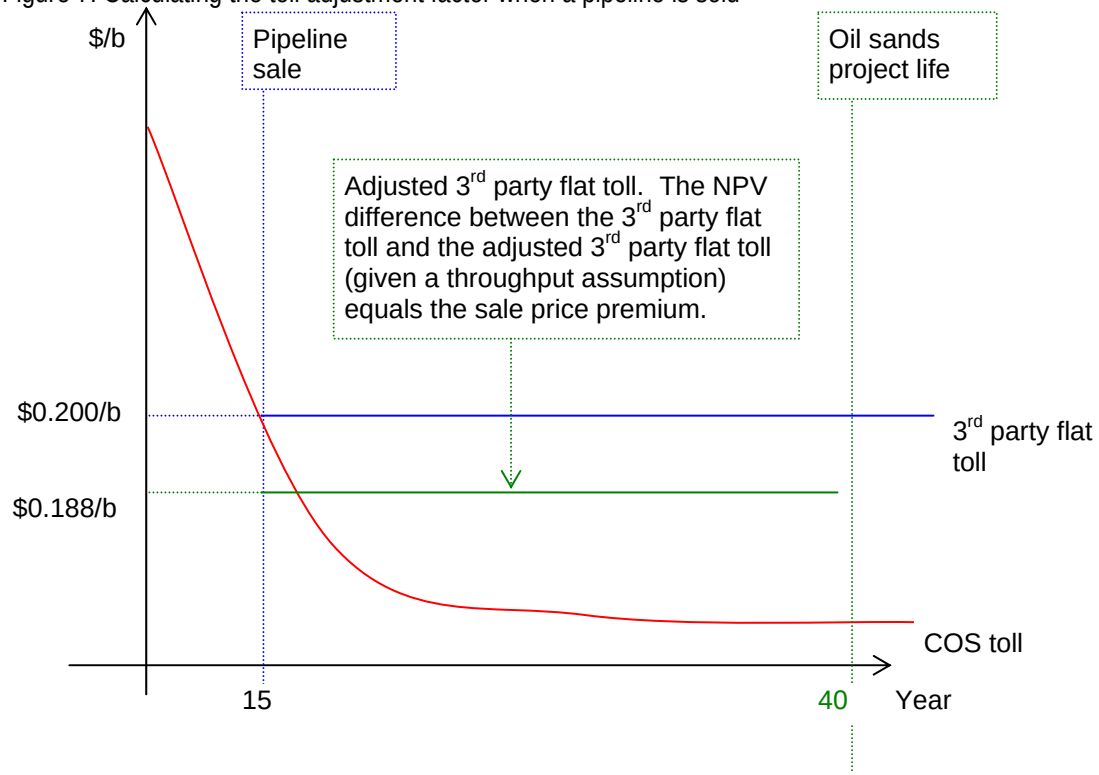
Calculation:

- The sale price premium is (27.5 – 22.5) = $5 million;
- The remaining life of the oil sands project is (40 – 15) = 25 years;
- The equivalent annual value is $678,531/year ($678,531/year for 25 years raises an NPV (@ 12.92% discount rate) equal to the sales price premium of $5 million);
- The adjustment factor (per barrel) is the equivalent annual value divided by throughput:

$$\frac{\$678{,}531/\text{year}}{55 \text{ million barrels/year}} = \$0.012/\text{barrels}$$

Figure 7, the post-sale pipeline toll is $0.188/barrel. This is the pre-sale toll ($0.200/barrel) less the adjustment factor ($0.012/barrel).

Figure 7: Calculating the toll adjustment factor when a pipeline is sold



5.2.4 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 cost of service calculation, and if that share of the pipeline's annual throughput capacity is less than 150% of the capacity required to transport the annual EUB–approved bitumen production from the owner's project, the full annual capital depreciation is charged against the owner's cost of service, 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 EUB-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 cost of service is prorated based on the percentage of the pipeline that is project related.

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

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;
- AEUB 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:

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

5.2.5 Cost Rules for Capital Additions to Non-Basic Pipelines

Two types of capital costs are used in cost-of-service 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 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 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.

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:

$$\frac{\$25 \text{ million} + \$20 \text{ million}}{20 \text{ years}} = \$2.25 \text{ million/year}$$

5.3 Cogeneration Plants

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 7.1(4)(a)

Cogeneration facilities use a single fuel source—usually natural gas—to produce both thermal and electrical energy. Steam produced from burning natural gas provides heat for oil sands project purposes. It also drives turbines that produce electricity for oil sands project purposes or sale.

Determinations of allowed costs related to cogeneration plants take into account the amount of steam or electricity used by the project and the percentage of the plant that is owned by project owners.

5.3.1 Valuing Steam and Electricity

Good or Services?

> The *Oil Sands Royalty Regulation, 1997,* section 7.1(4) defines the provision of thermal energy and the transmission and distribution of electricity as services.
>
> Electricity itself is defined as a good. Natural gas is also considered to be a good.

Basic services (see 9.2.2 "Basic Services") are valued on a cost-of-service basis.

Goods are valued on a fair market value basis whenever this is possible. When a representative fair market value is not available, cost-of-service valuation is used instead.

Department business rules recognize the unique characteristics of steam and electricity production. The provision of steam and electricity are inextricably linked in a cogeneration plant. As a result, the valuation methodology addresses the provision of combined heat and power (CHP).

5.3.1.1 Fair Market Value–Based Valuation for Electricity

The fair market value of electricity is calculated by using a simple average of the prices of market instruments used in electricity-related transactions. A multiple price-based approach should reduce the volatility of any single market instrument.

The prices used to calculate a fair market value must be readily available and appropriate. The following principles apply:

1. The price is associated with a market instrument that is publicly traded and reported.

2. The instrument is used for ongoing transactions for the delivery of electricity within a current period. A one-time transaction or a finite series of historical transactions is not appropriate.

3. Ideally, for periods of less than one month, there are no reporting gaps. If gaps exist, they should not introduce any bias with regard to the instrument's price.

4. The price represents an arm's-length transaction.

5. The price is quantifiable as an electricity cost. It does not include the cost of transmission or system support services and is not based on heat rates.

6. The instrument's price is charged to the delivery month rather than the month when electricity was purchased.

7. The calculation of fair market value should include as many prices as possible: i.e., the prices of all instruments that meet the principles listed above.

The preceding seven rules provide for a process that

- is straightforward and transparent
- eliminates the need to decide on arbitrary weightings in the absence of volume information, and
- uses a simple average to reduce price distortions

The following formula is used to calculate fair market value for electricity:

$$FMV = \frac{\sum_{i=1}^{n} P_i}{n}$$

i	=	the number of available prices (The value of i ranges from 1 to n, where n is the total number of prices available)
Pi	=	the price of instrument i
FMV	=	fair market value

The simple average approach is appropriate because a publicly available traded price is sufficient, and there is no need for a specific volume to be traded to constitute a liquid and fair market. Each valid price will have an equal weighting within the average regardless of how much volume is traded in that instrument, the number of trades, or the number of traders (i.e., the volume traded would not have an effect on whether the price calculated represented a fair market value or not. Monthly prices will better reflect variations in the different instrument markets.

The calculation of the monthly value for each component will vary. For example, the Power Pool price would be the published monthly average Pool price for each month. For forward components, the price will be set to reflect the settlement price for each instrument. For example, the “Next Calendar Year” for 2003 would be that set on the last trading day of 2002: the month is set at the last trading day of the previous month, etc. Day Ahead, Balance of the Month, and Rest of Calendar Year would all use an average of prices. Some forward prices may need further examination to ensure they meet the principles, such as "balance of month" and "rest of year".

Examples of fair market value calculations

Example #1 - General

Instrument Prices ($/MWh)	Description	Jul	Aug	Sep
Pool Average	Average of prices for month	26.41	32.03	45.70
Day Ahead	Average of prices from last day of previous month to second last day of current month	30.33	29.59	47.98
Balance of Month	Average of prices from beginning to last day of the month	31.97	31.89	43.10
Prompt Month	Settlement price in the previous month	35.00	35.06	41.50
Prompt Month+1	Settlement price from two months previous	39.25	37.40	35.15
Prompt Quarter	Settlement price from the previous quarter	36.00	36.00	36.00
Prompt Quarter+1	Settlement price from two quarters previous	47.75	47.75	47.75
Prompt Quarter+2	Settlement price from three quarters previous	n/a	n/a	n/a
Rest of Year	Average of prices from beginning of year to end of month	40.89	40.64	41.37
Next Calendar Year	Settlement price from previous year	38.50	38.50	38.50
Electricity FMV		**36.23**	**36.54**	**41.89**

Given the prices of the different instruments, the fair market value of electricity would be $36.23, $36.54 and $41.89 per MWh for July, August and September 20__, respectively. If another price became available, it would be included in the average as follows:

In example #2, the additional price has caused only a slight change to the fair market value.

EXAMPLE 2 - Additional Price Available

Instrument Prices ($/MWh)	Description	Jul	Aug	Sep
Pool Average		26.41	32.03	45.70
Day Ahead		30.33	29.59	47.98
Balance of Month		31.97	31.89	43.10
Additional Price	---------->	**36.59**	**39.15**	**45.02**
Rest of Year		40.89	40.64	41.37
Next Calendar Year		38.50	38.50	38.50
Electricity FMV		**36.27**	**36.80**	**42.21**

As shown in the following example, using a simple average approach reduces price fluctuations that may arise within any one trading instrument. In this example, August's pool price is significantly higher than July's. September's pool price is the same as August's, while the prompt month contract is much higher. Significantly higher values for one price component generally result in a small increase in fair market value.

Note

Since volumetric trading information is not generally available, fair market value–based electricity valuation does not include

- minimum volumes that would eliminate some prices
- calculations based on volumes traded

EXAMPLE 3 - Higher Prices

Instrument Prices ($/MWh)	Description	Jul	Aug	Sep
Pool Average	---------->	26.41	**65.21**	45.70
Day Ahead		30.33	29.59	7.98
Balance of Month		31.97	31.89	43.10
Prompt Month	---------->	35.00	35.06	**78.21**
Next Calendar Year		38.50	38.50	38.50
Electricity FMV		**36.23**	**40.23**	**45.97**

5.3.1.2 Cost of Service–Based Valuation for Electricity and Steam

Electricity produced outside an oil sands project is considered a good, not a service, and is therefore subject to fair market value considerations. If fair market value can be established, there is no need to use a cost-of-service approach. If there is no fair market value, the value of electricity is subject to cost-of-service determinations.

Steam, whether produced inside***** or outside***** a royalty project is defined as a basic service: therefore, a cost-of-service approach is needed to value the steam depending on whether it was obtained from inside or outside the project.

The cost-of-service calculation for steam and electricity uses a modified version of the methodology applied to NAL non-basic pipelines. A fundamental principle of all cost-of-service determinations is that the oil sands project should not subsidize the cost of non-project operations. The use of capital and operating cost allocation methods mitigates the risks of cross-subsidization.

Example 1

Consider an oil sands project that includes steam facilities within the project and electricity facilities outside.

- The steam costs are part of the project's allowed cost base and are treated the same way as other allowed costs. No cost-of-service determination is required.
- The electricity costs would be allowed at fair market value, if one could be determined. Only if a fair market value could not be established would a cost-of-service approach be necessary.

Example 2

Consider an oil sands project that uses steam and electricity facilities that are not part of the project.

- Steam costs would be calculated using a cost of service approach. The allowed rate of return would be the same long-term bond rate used in calculating the project's return allowance.
- The electricity costs would be allowed at fair market value, if one could be determined. Only if fair market value could not be established would a cost-of-service approach be necessary.

5.3.1.3 Valuing Steam and Electricity from a Cogeneration Plant

The following rules apply to non-arm's-length, natural gas–turbine-powered cogeneration plants equipped with heat-recovery steam generators (HRSG). The rules recognize that cogeneration plants provide both heat and power to oil sands projects. The determination of allowed costs includes consideration for their combined effect.

1. **If the steam-generating portion** of the cogeneration plant **is outside** the oil sands project, the cost of service must be determined—just as if the plant was a stand-alone steam generator. The long-term bond rate is used for the rate of return on capital.

2. **If the steam-generating portion is inside** the oil sands project, capital and operating cost allocations are determined in the same manner as if the steam portion was outside the project, regardless of how electricity is valued. (see 5.3.5.1, "Steam")

3. **When the electricity-generating portion** is outside the oil sands project, and when fair market value for electricity cannot be established, a cost of service approach is used to value the electricity. The long-term bond rate (LTBR) is used to calculate the rate of return on capital. The deemed cost of debt is the LTBR plus 1%:

the deemed cost of capital is the LTBR plus 4%. The deemed debt / equity ratio is 30% / 70 % (see 5.3.5.2, "Electricity".)

4. **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 air is 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 air is 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. **Fuel allocations** in cost-of-service determinations for steam vary depending on whether a fair market value can be established for electricity. The same rules for fuel allocations apply whether the steam is generated inside or outside the royalty project.

If a fair market value for electricity exists, NAL steam and electricity are charged at the lesser of the following:

- Electricity is charged at fair market value, and steam on a fuel-charged-to-steam (FCS) basis assuming a heat recovery steam generator operating with a thermal efficiency of 85%, or
- Electricity at actual amount charged to the project, and steam on a FCS basis in accordance with the calculations described on in 5.3.1.3.1, "Sample Calculations".

If there is no fair market value for electricity, steam and electricity are charged at the lesser of the following:

- Electricity at cost of service with fuel charged to power (FCP) equal to all fuel (gas turbine and duct fired) minus FCS, and steam on a FCS basis assuming a thermal efficiency of 85%; or
- Electricity at actual amount charged to the project; and steam on a FCS basis in accordance with calculations described in 5.3.1.3.1, "Sample Calculations".

The "lesser of" rule will only apply when the operator has appropriately demonstrated the required measurement for calculations described in 5.3.1.3.1, "Sample Calculations", i.e., if the formula cannot be used, then FCS will always be at a thermal efficiency of 85%.

For the first cases in both of the above scenarios, the FCS of 85% reflects the average fuel used (i.e., thermal efficiency) to generate steam in once through steam generators (OTSG), and ensures that the steam side of the project is no worse off cost-wise by using a HRSG. The remainder of the fuel balance, i.e., the amount of the gas turbine (GT) fuel and duct-firing portion not included in FCS, is allocated to electricity. The allowed cost of electricity to the project is based on electricity COS determination, if there is no fair market value for electricity.

For the second cases in both of the above scenarios, when FCS is determined according to the "formula", the amount of sensible heat captured by the HRSG from the GT exhaust, the amount of duct firing and the amount of HRSG flue gas use allocated to steam must all be defined. This test uses the actual value of electricity charged and a COS determination for steam that has fuel allocated according to the formula.

Under the formula, if there is no duct firing, the fuel is allocated assuming a HRSG efficiency of 86% (this is intended to approximate the 85% value use under the first case). When there is duct firing, the formula is dynamic giving the steam side a possible uplift (lower fuel cost when the HRSG is duct fired with high efficiency) as well as a downside, but still within a reasonable range of expectations.

5.3.1.3.1 Sample Calculations

The following calculation-steps illustrate the "fuel charged to steam" formula. Electricity is valued at the actual amount charged. Steam-related costs are determined by using a cost-of-service calculation.

1. Calculate the portion of the sensible heat captured in the steam resulting from duct firing in the generator. (HRSG)

   – Multiply the actual (measured) volume of duct-firing fuel by the actual (measured) HRSG efficiency.

2. Calculate the portion of the sensible heat captured in the steam resulting from the gas turbine fuel.

   – Subtract the amount calculated in Step 1 from the total actual (measured) sensible heat.

3. Calculate the portion of the energy in the HRSG flue gas charged to steam.

   – (3.1) determine the portion of the energy in the HRSG flue gas resulting from duct-firing fuel:

Subtract the amount calculated in Step 1 from the total actual (measured) volume of duct-firing fuel.

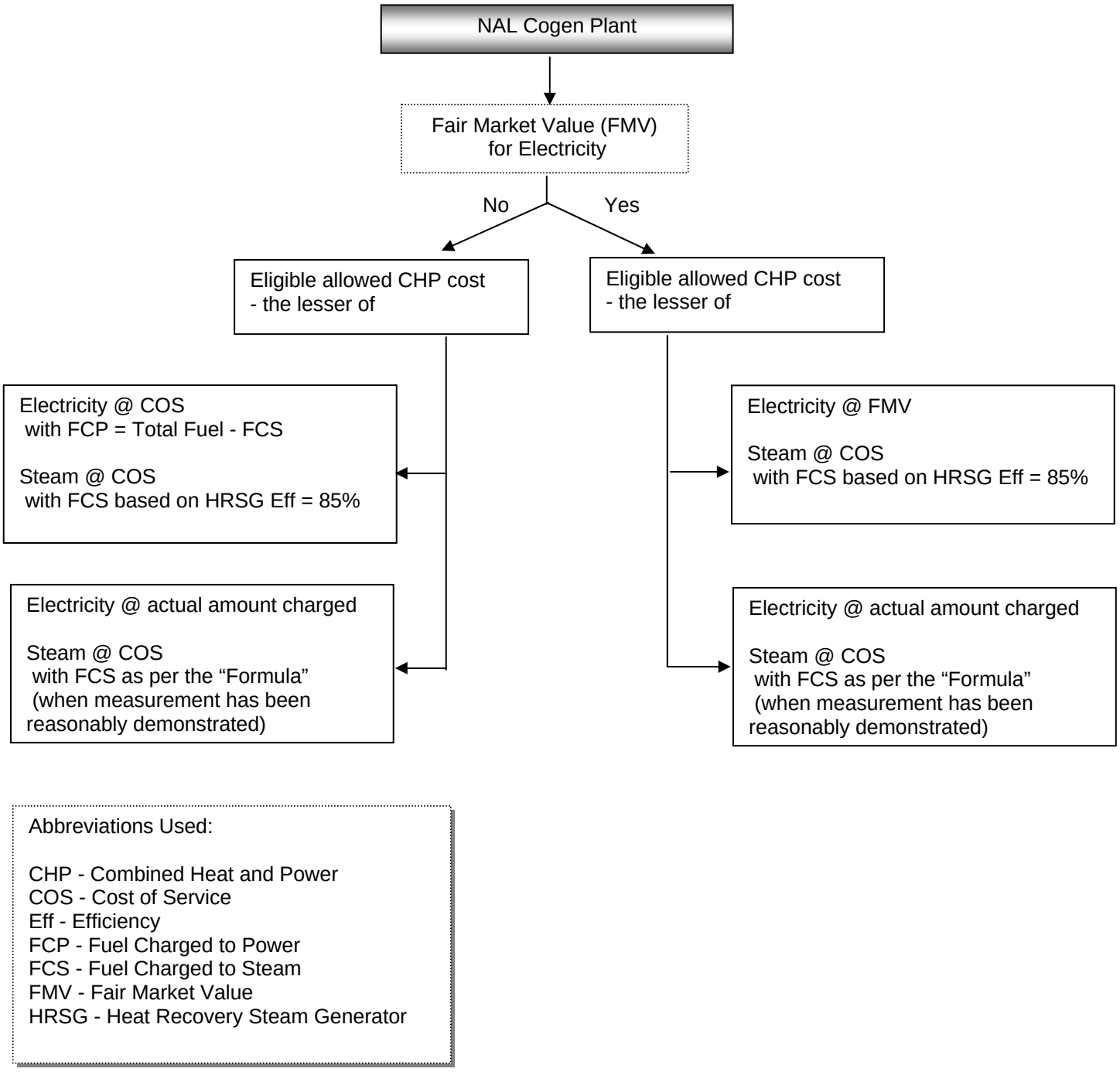
- (3.2) determine the portion of the energy in the HRSG flue gas resulting from gas turbine fuel:
  Subtract the amount calculated in Step 3.1 from the total actual (measured) volume of HRSG flue gas.
- (3.3) determine the percentage of sensible heat in the steam:
  Divide the amount calculated in Step 2 by the total, measured gas turbine fuel.
- (3.4) determine the portion of turbine-related generator flue gas energy that should be charged to steam:
  Multiply the amount calculated in Steps 3.2 by the amount calculated in Step 3.3.

4. Calculate the gas turbine fuel portion of the fuel charged to steam:
Add the results of Step 2 and Step 3.4.

5. Calculate the duct-firing fuel portion of the fuel charged to steam.

6. Determine the total volume of fuel charged to steam:
Add the results of Step 4 and Step 5.

Figure 8: Allowed costs for non-arm's-length cogeneration



FUEL CHARGED TO STEAM (FCS) CALCULATIONS w/r HRSG EFFICIENCIES (fired & unfired)

Data inputs in **blue** based on measured and manufacturer's data
Sensitivity changes reported in the Summary Table are determined by **red** inputs

Manufacturer's Data (GJ/day)

	Unfired HRSG	Fired HRSG
GT fuel	24,735	24,735
Steam sensible heat	10,149	18,239
HRSG flue gas	4,138	4,901
Duct firing fuel	-	8,853
HRSG efficiency	71%	79%

NOTE: the formula was run with different HRSG efficiencies that encompasses the experience with actual operations. Industry has suggested that a unfired HRSG (no duct firing) efficiency of 71% is reasonable, and 79% for a fired HRSG.

SUMMARY TABLE

Unfired HRSG Efficiency	Unfired FCS Efficiency	Fired HRSG Efficiency	Fired FCS Efficiency
95%	86%	95%	89%
90%	86%	90%	88%
85%	86%	85%	86%
80%	86%	80%	85%
75%	86%	79%	85%
71%	86%	75%	84%
70%	86%	70%	83%
65%	86%	65%	82%
60%	86%	60%	81%
55%	86%	55%	80%
50%	86%	50%	80%
45%	86%	45%	79%
40%	86%	40%	78%

STEPS	Formula with Unfired HRSG			Formula with Fired HRSG		
1	**Steam sensible heat from duct firing**		—	**Steam sensible heat from duct firing**		6,994
	Duct firing fuel	-		Duct firing fuel	8,853	
	HRSG efficiency	71%		HRSG efficiency	79%	
	Steam sensible heat from duct firing	—		Steam sensible heat from duct firing	6,994	
2	**Steam sensible heat from GT**		10,149	**Steam sensible heat from GT**		11,245
	Total steam sensible heat	10,149		Total steam sensible heat	18,239	
	Less duct firing sensible heat	-		Less duct firing sensible heat	6,994	
	Steam sensible heat from GT	10,149		Steam sensible heat from GT	11,245	
3	**HRSG flue gas chargable to steam**		1,698	**HRSG flue gas chargable to steam**		1,383
	Duct firing fuel	-		Duct firing fuel	8,853	
	Duct firing sensible heat	-		Duct firing sensible heat	6,994	
3.1	Duct firing loss	-		Duct firing loss	1,859	
	HRSG flue gas	4,138		HRSG flue gas	4,901	
	Duct firing loss	-		Duct firing loss	1,859	
3.2	Flue gas loss due to GT	4,138		Flue gas loss due to GT	3,042	
	Steam sensible heat form GT	10,149		Steam sensible heat form GT	11,245	
	Total GT fuel	24,735		Total GT fuel	24,735	
3.3	Sensible GT heat/ GT fuel	41%		Sensible GT heat/ GT fuel	45%	
	Sensible GT heat/ GT fuel	41%		Sensible GT heat/ GT fuel	45%	
	Flue gas loss due to GT	4,138		Flue gas loss due to GT	3,042	
3.4	HRSG flue gas chargable to steam	1,698		HRSG flue gas chargable to steam	1,383	
4	**Total FCS from GT**		11,847	**Total FCS from GT**		12,628
	Steam sensible heat from GT	10,149		Steam sensible heat from GT	11,245	
	HRSG flue gas chargable to steam	1,698		HRSG flue gas chargable to steam	1,383	
	Total FCS from GT	11,847		Total FCS from GT	12,628	
5	Total FCS from duct firing		—	Total FCS from duct firing		8,853
6	**TOTAL FCS:**		11,847	**TOTAL FCS:**		21,481
	Total FCS from GT	11,847		Total FCS from GT	12,628	
	Total FCS from duct firing	-		Total FCS from duct firing	8,853	
	TOTAL FCS:	11,847		TOTAL FCS:	21,481	
	FCS Efficiency (financial measure)		86%	**FCS Efficiency (financial measure)**		85%
	Total steam sensible heat	10,149		Total steam sensible heat	18,239	
	Total FCS	11,847		Total FCS	21,481	
	Total steam / total FCS	86%		Total steam / total FCS	85%	

5.3.2 Allocating Capital and Operating Costs

A steam or electricity 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 energy or steam the plant would have produced had it operated at its maximum continuous rating for the whole year.

5.3.3 Shared Costs

The capital and operating costs of shared facilities, such as the operating control room for stand-alone steam plant, stand-alone electricity power plants, or cogeneration plants, is to be allocated to steam and electricity in proportion to the capital cost of the facilities incurred directly for each of their respective "unshared" or single purpose facilities.

5.3.4 Depreciation

Steam and electricity plant capital are depreciated on a 5% straight-line basis over 20 years.

The Minister has the discretion to review and modify this rate as required. See OSR'97 section 7.1(2)(c)(i).

5.3.5 Rate of Return on Capital

5.3.5.1 Steam

Steam is a basic service. As a result the allowed rate of return on capital (RORC) is the long-term bond rate (LTBR). The same rate would apply for royalty purposes if the steam facility were treated as part of the oil sands project.

5.3.5.2 Electricity

The allowed rate of return on capital (RORC) is calculated using a pre-tax weighted average cost of capital formula, as follows:

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

Deemed Debt Percentage = 30%

Deemed Equity Percentage = 70%

Deemed Cost of Debt = Long-Term Bond Rate plus 1%

Deemed Cost of Equity = Long-Term Bond Rate plus 4%

Deemed Capital Structure = 30% debt and 70% equity

Deemed Corporate Income Tax Rate = the rate the owner applies to the asset on his tax return

5.3.6 Cost Rules for Sales of Cogeneration Plants

If a project-owned cogeneration plant is sold or transferred, and if the sales price is higher than the plant's undepreciated capital cost, a new charge-out rate must be established. This ensures that the Crown does not pay for capital costs it already paid for through pre-sale cost-of-service depreciation.

The new rate reflects the difference between the sales price and the undepreciated value of the plant. This amount is called the sale price premium. The adjustment factor is the flat rate that makes the plant's net present value (NPV) equal to the sale price premium.

The adjustment factor is calculated at the time of the plant sale and applies for the life of the project. Corrections can be made if the Department finds that the estimates regarding project life or plant output were inaccurate.

5.3.6.1 Calculating the Adjustment Factor

When a cogeneration plant is sold, its charge-out rate is adjusted at the time of sale. The following business rules apply:

1. The original plant owner determines
   - the sales price premium
   - the remaining expected life of the oil sands project at the time of the plant sale
   - the estimated output of the plant for the remaining expected life of the oil sands project

2. The Department of Energy reviews and approves these determinations.

3. The plant owner calculates the annual charge-out rate adjustment factor that will be used to calculate the price. This calculation only needs to be made once.

$$\text{Adjustment factor } (\$/m^3) = \frac{\text{Estimated annual value of the sale price premium}}{\text{Estimated annual plant output}}$$

The discount rate in the adjustment factor calculation is determined using the methodology to calculate the allowed rate of return on capital for NAL plants subject to a cost of service calculation, under the Regulation. Special Circumstances: Selling a Plant Together with Other Assets

If a cogeneration plant is sold together with other assets, the parties involved in the transaction prepare a sales agreement that assigns a value to each asset. The Department of Energy may challenge the assignment of asset values by using the dispute resolution and appeals process (see Chapter 8, "Dispute Resolution and Appeals"). Federal tax authorities may challenge the valuation in court.

5.4 Custom Processing

If a project asset is used to provide non-arm's-length custom processing services to other oil sands royalty projects, the non-arm's length rules in Chapter 9 apply.

5.5 Hedges

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 10(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 Oil Sands Royalty Regulation. 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.

Hedging costs are, of course, still subject to the criteria in *section 2 of Schedules 1 and 2* of the Regulation.

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 and the costs of entering into the contract may be allowed costs.
- 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 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 contract.

Costs of hedging currency risk related to the purchase of equipment from abroad for a project can be allowed costs of a project.

5.6 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.

5.6.1 Cost Rules for Research

Oil Sands Royalty Regulation, 1997 (AR 185/97), schedule 1, section 2(e)(ix), re non-qualifying joint ventures

Oil Sands Royalty Regulation, *1997* (AR 185/97), schedule 2, section 2(e)(ix), re qualifying joint ventures

To be eligible for deduction as allowed costs, research costs must comply with the following rules:

- The research must be reasonable and 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 oil sands royalty 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, within the parameters of section 18 of the Regulation, be included in determining the project's **prior net cumulative balance**. (see 2.3.10, "Prior Net Cumulative Balance")

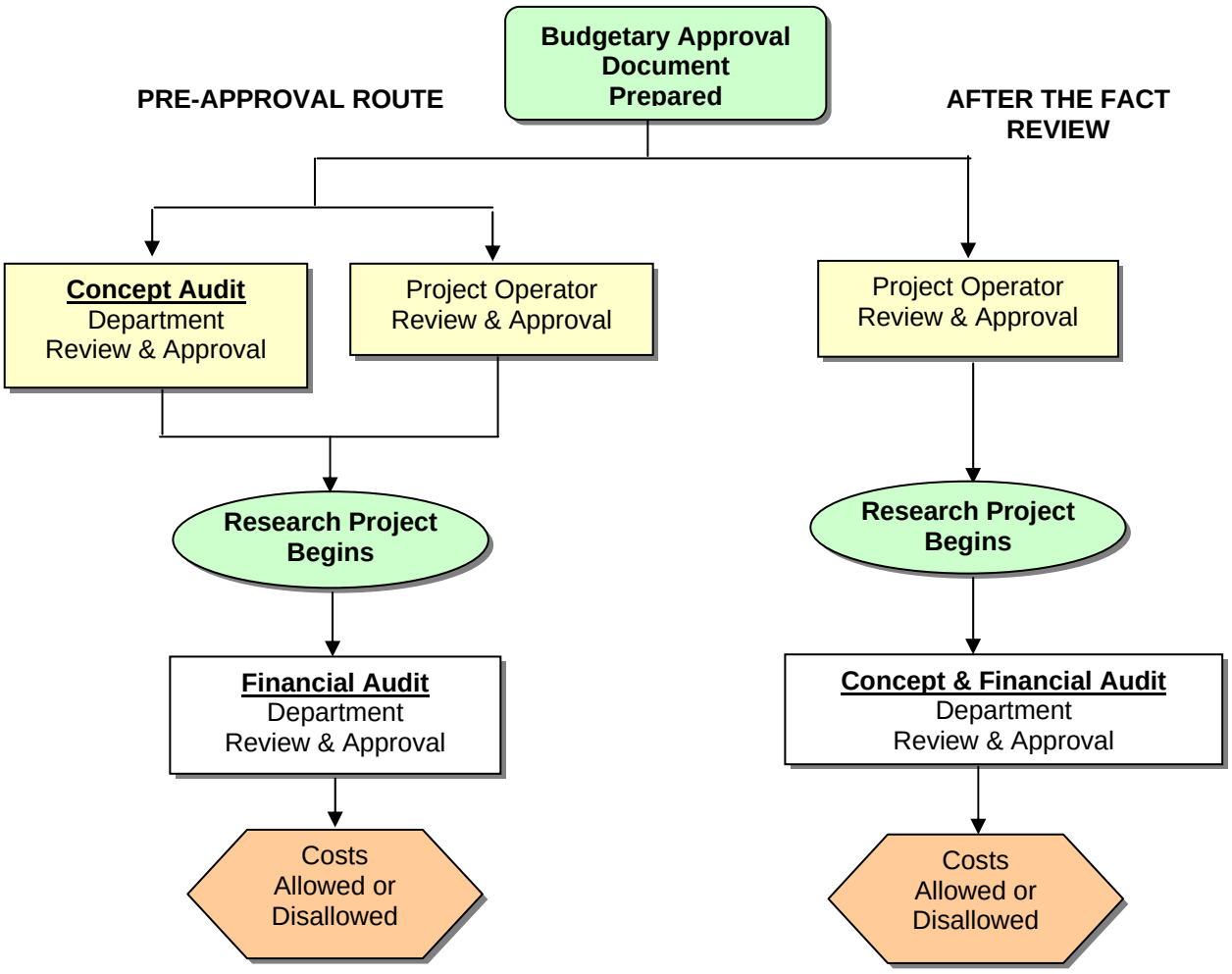
- Claimed research costs must reflect an actual financial transaction* that is supported by documentation.
  - Project operators should be prepared to provide sufficient information to support the claim of eligibility for research costs.
- Only net research costs are allowed.
  - With the exception of 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.) See *section 3(j)(ii) of Schedules 1 and 2*.
- Project owners, who recover research costs from other industry participants, must include the recovered amounts as "other net proceeds" (see 4.2.3.1, "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 *Oil Sands Royalty Regulation, 1997* 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.

Auditing Research Costs

All research costs claimed by an oil sands royalty project are subject to concept and financial audits conducted by the Department. A financial audit is conducted once a concept audit has found the research costs to be eligible, and once the costs have actually been incurred.

For details about financial audits, see 6.8, "Financial Audits". For details about concept audits, see 5.6.4, "Concept Audits".

Figure 9 - Approving and auditing research projects



5.6.2 Examples of Allowed Research Costs

Project operators are encouraged to request a concept audit (see 5.6.4, "Concept Audits") before undertaking research activities. This minimizes the risk that expenditures will be disallowed during financial audits conducted by the Department.

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 oil sands 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
- basic research for qualifying joint ventures

What is basic research?

Basic research is research designed to gain general knowledge or understanding rather than to address a specific technological challenge.

5.6.3 Examples of Research Costs That Are Not Allowed

- basic research for non-qualifying joint ventures
- research-related management and membership fees
- market research to determine upgrader requirements
- costs related to non-arm's-length transfers of proprietary research or proprietary technology, including research publications and licensed research or technologies

5.6.4 Concept Audits

Concept audits verify that a proposed or current research project or activity is directly attributable to an oil sands royalty project. For example, an OSR project owner may wish to conduct applied research that is marginally applicable to the project. If a concept audit concludes that such research is not "directly attributable," as required by the Regulation, the cost of the research is ineligible as an allowed cost. Alternatively, if the audit concludes that some or all of the research is directly attributable to the project, a corresponding portion of the research cost is eligible as an allowed cost.

Concept audits are conducted on two occasions:

- at the planning stage of a research project, when a project owner has submitted a request for an advance ruling (see 7, "Advance Rulings") to pre-approve a proposed research project
  - Project owners are advised to coordinate their requests for a pre-approval with their own, corporate approval processes. This facilitates Department–owner discussions and consensus about the purpose of the proposed research project.
  - A budgetary approval document should be submitted with the request.
- as part of a financial audit (see 6.8, "Financial Audits") conducted by the Department

In conducting a concept audit, the Department considers

- how the research advances knowledge which has specific, practical application to the project
  - The research does not have to be successful. However, for research costs to be eligible as allowed costs, the research must demonstrate the potential to provide meaningful insight or understanding of a problem or issue that directly affects the oil sands royalty project.
- the type and nature of deliverables
- the location of the research activity
  - Off-site research may be eligible. Supporting documentation must be provided to show why an off-site location is preferable, especially if the research is being conducted in facilities outside Alberta.
- whether or not the research findings will be applicable within a reasonable time frame
  - The rule of thumb is that research should be applicable within five years of the date when a research project is first launched. Longer time frames may be approved if the project operator can provide a business case to support the extension.

5.6.5 Claiming Research Costs

To claim research costs, the OSR project operator must submit a budgetary approval document—such as an authorization for expenditure form—that supports the link between the corporate decision to undertake a specific research activity and the actual expenditure and results. The approval document creates a paper trail that facilitates the Department's audit process and ensures accountability.

The budgetary approval document must be signed by the corporate officer authorizing the expenditures. It must include the OSR project approval number and the legal description of the oil sands leases to which research costs are to be allocated. It must also describe:

- the purpose of the research and demonstrate that it is directly attributable to the project, as required by the Regulation
- the nature of the research project and its scope, including any external approvals that may be required
- the research participants
- the research time frame
- expected deliverables and due dates
- the location of research
  - Supporting rationale must be provided if the lease is located outside Alberta.
- the planned expenditures
  - The categories of research costs must be itemized. Allocations to capital or operating budgets must be identified and annual and cumulative amounts must be provided.
- any financial support which is being provided through Alberta programs or from other jurisdictions

A budgetary approval document must be submitted to the Department even if the research project was pre-approved.

5.7 Cross-Boundary Wells

Cross-boundary wells are horizontal crude bitumen production wells that have been drilled across the boundaries of adjacent oil sands royalty 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. The wells also cross Oil Sands Conservation Act scheme approvals granted by the Alberta Energy and Utilities Board.

The amalgamation of any affected oil sands royalty 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.

Most operators are already complying with this practice. In any other cases, this policy should be applied as of the March 2006 (publication of this guideline).

5.8 Grandfathering

"Grandfathering" refers to the idea that oil sands royalty projects will continue to be governed by the Regulations and business rules in place at the time that business

arrangements were made and will not be subject to subsequent Regulation or business rule changes.

The Department cannot offer assurances that royalty regulations and business rules will never change. Government cannot bind the hands of its successors with respect to regulations and rules. Legislature and the Government at all times have unfettered power and discretion in the development and enactment of law and regulations applicable to the subject matter of oil sands. If all regulation and business rule changes were grandfathered there would be a variety of royalty rules for different projects, depending on the timing of their approvals, which would be inconsistent with the principle of a single generic royalty regime. Another consideration is that fully grandfathering all royalty regulations and business rules may result in industry missing out on necessary and beneficial royalty rule changes driven by significant economic or environmental factors.

In recognition, however, of industry's concerns over consistency and fairness, wherever appropriate and subject to the caveats expressed above, the Department will try to adhere to the following principles:

1. Future royalty regulation and rule changes will be implemented prospectively, not retroactively, and will apply to all oil sands royalty projects

2. Business rules will be developed expeditiously, and the use of advance rulings will be encouraged to ensure a common understanding by government and industry of royalty treatment.

3. Business rules will reflect the underlying principles of the Oil Sands Royalty Regulation, 1997.

In addition, with respect to the effective date of business rules changes, the following must be considered:

1. A business rule that simply restates a provision of the Regulation has no operative effect of its own, and must necessarily relate to the same period as the corresponding section of the Regulation.

2. In the case of a business rule that provides guidance on how the Minister may exercise some discretion conferred on him:

a. If the discretion has already been exercised, and business rules are subsequently issued indicating the discretion will be exercised differently, the new business rule will apply prospectively to all projects. It will not be applied retroactively to projects previously subject to the original business rule.

b. If a provision of the Regulation or amendment takes effect retroactively, a business rule describing how the Minister will exercise his discretion with respect to this provision must also apply retroactively.

3. A business rule that states the Minister's interpretation of the Regulation will only be applied retroactively in exceptional circumstances. Factors to be considered prior to retroactive application would include, but not be limited to, how different the new interpretation is relative to a previous interpretation, fairness to all parties, and whether a recalculation of royalty can still be made.