Alberta Oil Sands Royalty Guidelines

Appendix

Oil Sands Royalty Guidelines
Due to the size of this document the guidelines are under separate cover.

Appendix A

Oil Sands Royalty (OSR) Glossary

Please find the Oil Sands Glossary at

Act	In this document, the *Mines and Minerals Act*.
abandonment	Converting a drilled well to a condition that can be left indefinitely without further attention.
actual financial transaction	A transaction that has actually been incurred is supported by documentation and has specific, practical application for an OSR Project.
advance ruling	The Department's statement on how it will interpret the applicable laws, policies and guidelines with respect to proposed business arrangements or specific allowed costs that relate to OSR Projects.
Allowed Cost	Costs described in the *Oil Sands Allowed Costs (Ministerial) Regulation* (OSAC) that are eligible for deduction from the *Oil Sands Royalty Regulation, 2009* Project revenues in the calculation of oil sands royalty.
API gravity	The gravity of crude bitumen as measured by a hydrometer and expressed in degrees on the American Petroleum Institute (API) scale. API gravity = (141.5/specific gravity) - 131.5. The lower the API gravity, the heavier and more viscous the bitumen. Athabasca bitumen has an API gravity number of less than 10°.
barrel	A measure of volume equivalent to 0.159 m^3. For example 1590 m^3 is the equivalent of 10,000 barrels. For BVM purposes use a conversion factor of 6.29234 barrels per m^3 as per the BVM Regulation section 1(5)(a).
basic service	A service: provided, using a core or supporting asset that is not part of the OSR Project, 1) without which oil sands products, could not be physically recovered, or 2) that is necessary for the maintenance or operation of a core or supporting asset.
battery	A system of tanks or surface equipment that receives natural gas or bitumen from one or more wells prior to delivery to market or other disposition. A battery may include equipment for separating and measuring oil, gas and water.

bitumen	A sticky, tar-like form of crude oil which is so thick and heavy that it must usually be heated or diluted before it will flow. At room temperature, bitumen is much like cold molasses. It typically contains more sulphur, metals and heavy hydrocarbons than conventional crude oil. See also: crude bitumen, cleaned crude bitumen and blended bitumen.
blended bitumen	Cleaned crude bitumen that has been blended or deemed to have been blended with diluent so that it can be transportable by pipeline.
catalyst	Assists a chemical reaction by lowering temperature or chemical requirements.
cleaned crude bitumen	Crude bitumen from which impurities have been removed sufficiently to allow it, when blended with diluent, to be transported by pipeline.
cold production Project	Cold production Projects are any in-situ Projects that do not apply thermal energy to the reservoir for recovery of crude bitumen. Examples of cold production Project are projects that utilize secondary and tertiary recovery methods, such as water floods or polymer floods.
common management	Common Management will be defined by an organizational structure in which a single entity has responsibility for the day-to-day business decisions regarding the operation of only the OSR Project and that reflect the economic interests of the OSR Project and no other activity.
cogeneration	Co-generation means concurrent production of more than one usable form of energy from a single fuel source. For example, electricity and steam.
condensate	A mixture of hydrocarbons that is present as a gas in an underground reservoir but that condenses into a liquid upon recovery.
Corporate overhead	Costs that are not directly and solely incurred for the purposes of Project operations.
Crown	In this document, the Government of Alberta (that is, the Crown in right of Alberta).
Crown rights	Surface rights or mineral rights which are owned by the Crown.
crude bitumen	Despite section 1(1)(d) of the *Mines and Minerals Act*, “crude bitumen” means a viscous mixture, mainly of hydrocarbons heavier than pentanes, that may contain sulphur compounds and that is obtained from oil sands and that may or may not flow to a well.
Crude oil	A combustible hydrocarbon usually processed into a variety of petrochemicals including gasoline, diesel, propane and many more.

cumulative cost	With regard to an OSR Project, the sum of (1) the OSR Project's prior net cumulative balance, (2) the OSR Project's allowed costs and (3) royalty paid to the Crown during the OSR Project's pre-payout Period.
cumulative cost balance	See net cumulative balance.
cumulative revenue	With regard to an OSR Project, the sum of Project revenue and other net proceeds received or receivable from the OSR Project's effective date onwards.
department	In this document, Alberta Energy.
development area	The lands and subsurface strata included as part of an OSR Project.
diluent	A hydrocarbon substance used to dilute crude bitumen so that it can be transported by pipeline.
disposition	Where any reference is made in the *Oil Sands Royalty Regulation, 2009* (OSRR09, OSAC or BVMR) to the disposing or disposition of anything, the reference shall be construed as referring to a sale or any other disposition of the thing to a person who by reason of the sale or disposition becomes its owner.
effective date	With regard to an OSR Project, the date on which the OSR Project is approved and from which royalty begins to be calculated under the terms of the OSRR09.
end of period statement (EOPS)	A type of royalty report required by the Department. An annual EOPS signed by an authorized officer is required for both pre-payout and post-payout OSR Projects. The statement provides a detailed summary of the financial- and production-related operations of the OSR Project.

engineering systems	A regularly interacting or interdependent group of assets with a defined common output, including, without limitation, the following systems: (i) boiler feed water treatment system, (ii) raw water system, (iii) fuel gas system, (iv) steam generation system, (v) electricity transmission system, (vi) control system, (vii) cooling water system, (viii) instrument air system, (ix) fire water system, (x) emergency power system, (xi) potable water lines, (xii) waste water lines, (xiii) sewer lines, (xiv) sour water lines, (xv) slop oil lines, (xvi) pipe racks.
escalating rent	A payment due from developers who wish to retain their oil sands rights to non-producing continued leases. Rent for such leases is charged on an escalating basis according to a schedule published in the *Oil Sands Tenure Regulation*.
fair market value	The Department's determination of the value of a good or service based on the value of comparable goods or services available on the open market.
freehold rights	Mineral rights that are not owned by the Crown in right of Alberta.
good faith estimate (GFE)	A type of royalty report required by the Department. A monthly GFE is required for post-payout OSR Projects. The estimate provides a detailed summary of the financial- and production-related operations of the OSR Project. It includes actual (or best estimates of) figures for previous months and forecasted figures for future months.

greenhouse gases (GHG)	Greenhouse gas means “specified gas” defined in the *Climate Change and Emissions Management Act* as any gas that traps heat near the Earth’s surface and includes, without limitation, carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs)and Sulphur hexafluoride (SF_6).
gross revenue	For an OSR Project, the Project revenue minus the cost of diluent contained in any blended bitumen included in the calculation of the Project’s revenue.
handling charges	For an OSR Project, all charges incurred in moving an oil sands product from the royalty calculation point to the disposition point.
hedges	Transactions that use long term contracts, futures contracts, swap arrangements and other financial instruments to mitigate price fluctuations and reduce the risk of an investment.
Information Letter	Publications issued periodically by the Department of Energy to advise industry clients of changes in policy and pricing, to communicate proposed changes to legislation and business rules, and to solicit feedback to proposals.
Information Bulletin	Publications used to notify industry regarding items such as proposed changes to legislation, regulations or operating procedures with the intent of soliciting feedback; new or changes to existing programs, projects, services, strategies or organizational structure; industry participation in department initiatives.
“inside” a Project	Lands, leases, operations, facilities and infrastructure specified in an approved OSR Project description are said to be “part of the OSR Project” or “inside the OSR Project.”
integrated Project	A project designated as such by the Minister, under section 8.1 comprising as a Project, integrated shared operations and an integrated upgrader.
integrated shared operations	In relation to an OSR Project, those operations such as utilities and off sites that provide services to the Project as well as to the integrated upgrader as described in section 14(1)(c.1).
in-situ	Latin for "in place." In oil sands recovery, all non-mining methods employed to collect bitumen deposits are in-situ.
integrated upgrader	In relation to an OSR Project, the portion or portions of an integrated project that in the Minister’s opinion form upgrader operations under section 8.1 or 14(1)(c.1).

long-term bond rate (LTBR)	The rate, published weekly by the Bank of Canada that is applied as the return allowance, to the net cumulative balance or net loss of an OSR Project.
measured use assets	One or more of the following engineering systems: (i) boiler feed water treatment system; (ii) raw water system; (iii) fuel gas system; (iv) steam generation system; (v) electricity transmission system.
mineral rights	The rights to explore for, produce, and sell the minerals contained in a parcel of land. This entitlement may accrue through freehold ownership or through a Crown leasing arrangement.
Minister	In this document, the Alberta Minister of Energy.
month	As defined in the OSRR09, the Period commencing at 8:00 AM on the first day of a month and ending immediately before 8:00 AM on the first day of the next month.
monthly royalty calculation (MRC)	A type of royalty report required by the Department. A monthly royalty calculation is required for pre-payout OSR Projects. It reports production, sales and royalty information for each oil sands product for the month.
net book value	For a capital asset, the original cost less accumulated depreciation.
net cumulative balance	The amount by which the cumulative costs of an OSR Project exceed its cumulative revenue. The net cumulative balance is sometimes referred to as the cumulative cost balance or the unrecovered balance.
net loss	For an OSR Project, the amount by which the allowed costs for a Period exceeds the sum of revenues and other net proceeds for the Period.
net revenue	For an OSR Project, the amount by which Project revenue exceeds Project costs (less other net proceeds) in a given reporting Period.
non-basic pipeline	Pipelines for transporting bitumen (or blended bitumen) to market (from a royalty calculation point to the point of disposition) are called non-basic pipelines. Similarly pipelines transporting diluents to an OSR Project are non-basic pipelines.

oil sands	Defined in the Mines and Minerals Act as ▪ sands and other rock materials containing crude bitumen ▪ the crude bitumen contained in those sands and other rock materials ▪ any other mineral substance (except natural gas) associated with the above-mentioned crude bitumen, sands or rock materials
oil sands product	Any product recovered from oil sands or any product obtained by processing oil sands, not solution gas.
oil sands royalty (OSR) Project	An OSR Project for which royalty calculation and reporting is governed by the OSRR09 and not a larger integrated Project of which the OSR Project may form a part.
opening balance	See prior net cumulative balance.
operator	An "operator" means the person who from time to time is shown in the records of the Department as the operator of an OSR Project or proposed project or if no such person is shown in the records of the Department, the person who is shown in those records as the lessee of the OSR Project, or proposed project respectively.
other net proceeds	Revenue (proceeds) earned as a result of selling, leasing or licensing OSR Project-related assets, technology or substances *other than* oil sands products.
"outside" a Project	Lands, leases, operations, facilities and infrastructure that are not specified in an approved OSR Project description are considered to be "outside the OSR Project."
participating interest	The proportion of ownership in the whole of an OSR Project that is held by any one OSR Project owner.
payout date	For a pre-payout OSR Project, the first day in the month in which the cumulative revenue of an OSR Project first equals the cumulative cost of the OSR Project.
Period	Each calendar year or portion thereof that occurs between an OSR Project's effective date and the date when OSR Project approval is revoked. If an OSR Project pays out during a year that year is divided into a pre-payout and a post-payout Period.
person	The term "person" includes a firm, trust, partnership, joint venture, government or government agency.
post-payout period	Each Period commencing on or after the payout date of an OSR Project.

pre-payout period	Each Period commencing before the payout date of an OSR Project.
prior net cumulative balance	For an OSR Project, the opening balance of costs less revenues incurred prior to the OSR Project's effective date.
processing plant	A facility for separating and recovering crude bitumen or for obtaining oil sands products from oil sands, crude bitumen or a derivative of crude bitumen that have been recovered, that is approved under the *Oil Sands Conservation Act*.
production month	The month in which an oil sands product is recovered or obtained and delivered to the royalty calculation point.
Project	See oil sands royalty Project.
Project description	The section of an OSR Project approval order that specifies the lands, leases, operations, and facilities that are considered to be "part of the Project" or "in the Project." The approved OSR Project description for a new OSR Project is called the initial Project description. When an OSR Project is amended, the approved description referred to as the amended OSR Project description.
Project operator	See operator.
Project owner	The lessee of oil sands rights and the person who, according to Land Titles Office records, has the right to recover oil sands from the development area of an OSR Project.
Project payout date	The date upon which the cumulative cost of the project equals the cumulative revenue.
Project revenue	The sum of the volume of each oil sands product delivered to the royalty calculation point times its unit price.
Project substances	Oil sands and oil sands products recovered from the development area of an OSR Project.
Project use threshold	This is a threshold that: (i) in respect to a capital asset or engineering system used on not more than one Project, 75%, and (ii) in respect of a capital asset or engineering system used on 2 or more Projects that are owned or operated by the same lessees or one or more affiliates of the same lessees, that the usage of the capital asset or engineering system is, in the Minister's opinion, dedicated almost exclusively to those Projects;

return allowance	A return on investment allowed in the calculation of oil sands royalty. For OSR Projects, the allowance is calculated using Canada's long-term bond rate. For pre-payout OSR Projects, a monthly return allowance is provided on the net cumulative balance for the month. For post-payout OSR Projects, a return allowance is provided if the OSR Project has a net loss at the end of the Period.
royalty	A share of production or equivalent revenue that is paid to the owner of a mineral resource in exchange for the use of that resource. Owners of mineral rights may lease these rights to oil and gas companies in exchange for a royalty.
royalty calculation point	For an OSR Project, the point at which the Crown's royalty share of the OSR Project's sales is measured. Generally, the point at which an oil sands product is removed from OSR Project lands, or where clean crude bitumen is first produced.
royalty-in-kind	For an oil sands project, the point at which the Crown's royalty share of the project's sales is measured.
Steam Assisted Gravity Drainage (SAGD)	An thermal oil recovery technology for producing heavy crude oil and bitumen, in which a pair of horizontal wells are drilled into the oil reservoir, one a few metres above the other. Low pressure steam is continuously injected into the upper wellbore to heat the oil and reduce its viscosity, causing the heated oil to drain by gravity into the lower wellbore, where it is pumped to surface by artificial or gas lift mechanisms.
sales price	The calculated value of the sales revenue divided by the sales volume.
sales revenue	The total proceeds from the sale of an oil sands product.
sales volume	The actual volume of the oil sands product sold.
spud	Commencement of the drilling of a well.
synbit	A blend of cleaned crude bitumen mixed with SCO for diluent in order to meet pipeline viscosity and density specifications.
synthetic crude oil	A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, that is obtained from crude bitumen and that is liquid at a temperature of 15 degrees Celsius and at a pressure of 101.325 kilopascals.
Total Acid Number (TAN)	Is a number (expressed in milligrams (mg) of potassium hydroxide needed to neutralize the acid in one gram of oil) used to indicate the acid content of a crude oil or blend.

unit price	For an OSR Project, the value of oil sands substances at the royalty calculation point.
unrecovered balance	See net cumulative balance.
West Texas Intermediate	A reference crude oil, the price of which is used in determining oil sands royalty rates.
upgrader	A facility used to upgrade bitumen to crude oil.
upgrading	The process by which heavy oil and bitumen are converted into lighter crude by increasing the ratio of hydrogen to carbon.
zone designation	A description of the stratigraphic interval for a particular set of mineral rights.

Appendix B

Forms Submission List and Related Information

Oil Sands Royalty and related reporting forms and information are available for download on the Department's website in Excel or PDF format (From the Department's website (http://www.energy.alberta.ca/), navigate to "Our Business," then to "Oil Sands," then "Forms."). All submissions must be made through the secure web application Electronic Transfer System (ETS) in Excel format.

Please note these Excel spreadsheets will be downloaded into a database – therefore no revisions to the forms' formats are allowed.

Refer to Section 7 of the Oil Sands Royalty Guidelines "Administration and Enforcement" for additional details to the forms listed below. If you have any concerns with form access and require assistance contact the "Oil Sands Royalty Account Inquiries" team. (See Appendix G, "Contact Information" or via the OS Reporting Mailbox - OSReport@gov.ab.ca).

Disclaimer: Forms referenced in these Guidelines are current as of the date of issue of the Guidelines. However, forms may change from time to time and the most current version will be found on the website.

Oil Sands Reporting Calendar

Royalty Project Application Forms

- Introduction to OSR Application Process
- Introduction to the Cost Allocation Process
- OSR New Project Application Checklist
- OSR Project Amendment Application Checklist
- Economic Evaluation Data Requirement (For New Applications, Amendments and Project Amendments)
- Prior Net Cumulative Balance: Summary, Capital Cost Detail, Operating Cost Detail, Revenue Detail

There is no OSR Project Application Form for download. The Project application is completed through an online application process.

Non-project Well Royalty Reporting Forms (NPR)

- Oil Sands Royalty Calculation Current Par Price/R Multiplier Letter
- Non Project Royalty Submission in XML Format
- Non Project Royalty Submission XML Schema
- Non Project Royalty Submission in Excel Format

Oil Sands Royalty Projects other than Transitional Agreements (OSR Projects, excluding Transitional OSR)

- MRC (OSRR 2009)* – Monthly royalty reporting template for Pre Payout OSR Projects for 2009 and later periods.
- GFE (OSRR 2009) – Monthly royalty reporting template for Post Payout OSR Projects for 2009 and later periods.
- Pre Payout EOPS (OSRR 1997) – Annual royalty reporting template for Pre Payout OSR Projects for 2008 and prior periods.
- Post Payout EOPS (OSRR 1997)– Annual royalty reporting template for Post Payout OSR Projects for 2008 and prior periods.
- Pre Payout EOPS (OSRR 2009) – Annual royalty reporting template for Pre Payout OSR Projects for 2009 and later periods.
- Post Payout EOPS (OSRR 2009) – Annual royalty reporting template for Post Payout OSR Projects for 2009 and later periods.

Crown Agreements (CSR Projects):

- CA MRC (OSRR 2009)* – Monthly royalty reporting template for Pre Payout CSR Projects for 2009 and later periods.
- CA GFE (OSRR 2009) – Monthly royalty reporting template for Post Payout CSR Projects for 2009 and later periods.
- CA Pre Payout EOPS (OSRR 1997) – Annual royalty reporting template for Pre Payout CSR Projects for 2008 and prior periods.
- CA Post Payout EOPS (OSRR 1997) – Annual royalty reporting template for Post Payout CSR Projects for 2008 and prior periods.
- CA Pre Payout EOPS (OSRR 2009) – Annual royalty reporting template for Pre Payout CSR Projects for 2009 and later periods.
- Post Payout EOPS (OSRR 2009) – Annual royalty reporting template for Post Payout CSR Projects for 2009 and later periods.

* Note: MRC amendments after the end of the period can be reported directly in schedule 6 of the Pre Payout End of Period Statement royalty template. Separate MRC filings are no longer required with the new royalty templates.

Transitional OSR Project – OSR045

- OSR045 GFE (OSRR 2009) – Monthly royalty reporting template for Post Payout OSR045 Projects for 2009 and later periods.
- OSR045 EOPS (OSRR 2009) – Annual royalty reporting template for Post Payout OSR045 Projects for 2009 and later periods.

Transitional OSR Project – OSR047

- OSR047GFE (OSRR 2009)– Monthly royalty reporting template for Post Payout OSR047 Projects for 2009 and later periods.
- OSR047 EOPS (OSRR 2009) – Annual royalty reporting template for Post Payout OSR047 Projects for 2009 and later periods.

Cost Analysis and Reporting Enhancement (CARE)

- See Appendix C

Operator's Forecast Report

- Instruction on How to Submit the Operator's Forecast Through ETS.
- Operator's Forecast Report

Advance Ruling or Discretionary Allowed Cost Form

- A request for discretionary allowed costs
- A request for advance ruling

Cost of Service Template Form

- A form to be filled when reporting the Cost Allocation Methodology Reports.

Appendix C

Cost Analysis and Reporting Enhancement (CARE) Reports and Related Information

CARE reports and related information are available for download on the Department's website in Excel or PDF format (From the Department's website (http://www.energy.alberta.ca/), navigate to "Our Business," then to "Oil Sands," then "Forms.")., All submissions must be made through the secure web application Electronic Transfer System (ETS) through ETS Correspondence in Excel format.
Please note these Excel spreadsheets will be downloaded into a database – therefore no revisions to the report formats are allowed.

Disclaimer: Reports referenced in these Guidelines are current as of the date of issue of the Guidelines. However, forms may change from time to time and the most current version will be found on the website.

Effective 2011 Reporting Periods and Forward

1. CARE Costs – In Situ Workbook
2. CARE Costs – Mining Workbook
3. CARE Project Workbook
4. CARE Revenue Workbook
5. CARE Western Canadian Select (WCS) Sales

Effective 2009 and 2010 Reporting Periods

1. CARE Volumetric, Operations, Reserves, Deposit and Reservoir Data Reports
    - Volumetric Data (Integrated) – Mining and In Situ
    - Volumetric Data (Non-Integrated) – Mining and In Situ
    - Operations Data – Mining and In Situ
    - Deposit Data – Mining
    - Reservoir Data – In Situ
    - Reserves Data – Mining and In Situ
2. CARE Operating Cost by Function Reports
    - Operating Costs – Mining
    - Operating Costs – In Situ
3. CARE Capital Cost by Function Reports
    - Capital Costs – Mining
    - Capital Costs – In Situ
4. CARE Revenues
    - Bitumen/Bitumen Blend Revenue – In Situ Projects
    - Bitumen Blend Net Calculation – In Situ Projects
    - Transportation Costs – In Situ Projects
    - Diluent Supplied to Stream – In Situ Projects
    - Other Oil Sands Product Revenue – Mining and In Situ Projects
    - Western Canadian Select (WCS) Sales

Related Information

1. CARE Online Training
2. CARE Training Presentation
3. CARE FAQ

Appendix D

CARE - Glossary

The following definitions are specific to Cost Analysis and Reporting Enhancement (CARE) reporting forms. Any costs reported are allowable based on the *Oil Sands Royalty Regulation, 2009* (OSRR09) and *Oil Sands Allowed Cost (Ministerial) Regulation* (OSAC).	
CAPITAL & OPERATING COSTS, OPERATIONS, VOLUMETRIC, and RESERVES DATA	
CAPITAL COST DEFINITIONS	
Bitumen Production Facilities and Equipment	For all primary, enhanced oil recovery (EOR), steam assisted gravity drainage (SAGD), cyclical steam stimulation (CSS) and other thermal in-situ Projects, this may include equipment at or near the producing wells including pump jacks, storage for chemicals, supplies and additives, chemical injection facilities, water injection facilities, additives injection facilities, steam injection facilities, diluent blending, metering and measurement equipment and bitumen storage tanks. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any “off project” buildings and structures directly attributable to the Project in accordance with the Regulations. Includes all on or off-road vehicles, buses, snow clearing equipment, ski-doo’s, aircraft, helicopters, boats, barges, fuel trucks, fire protection equipment, etc. dedicated to the Project or allocated portions of similar equipment.
Capitalization Methodology	Description of the capitalization policy adopted/used by the company. (e.g., Successful Efforts methodology, Full Cost methodology) Expressed as a narrative identifying dollar threshold determination and useful life measurement.
Co-Generation Plant(s)	Gas fired plant used to generate electric energy concurrently with thermal energy. Only includes the approved oil sands royalty (OSR) Project costs for the cogeneration plant(s), and associated infrastructure, supplying steam and electricity to the Project. It is necessary to segregate the capital associated with the generation of electricity from that used for generation of steam. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any “off project” buildings and structures directly attributable to the Project in accordance with the Regulations.

Delineation and Development	This relates to well activities that determine the boundaries or the extent of a reservoir or well activities within the proved reserve area. Includes seismic, core-hole testing, delineation and development drilling, well completions and all other related, incidental costs incurred on Project lands.
Emulsion Treating & Cleaning and Solid Waste Disposal	For in-situ Projects, include all costs associated with cleaning of produced bitumen, including gas separators and processing equipment, treaters, water reclamation and waste water disposal facilities, heaters, pumps, process tanks, solids waste removal or other waste product removal from the treatment of oil sands substances and disposal, solid waste landfills and salt caverns, processing related diluent blending and/or recovery, vapour recovery, metering and measurement devices, communications, buildings and shelters. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any "off project" buildings and structures directly attributable to the Project in accordance with the Regulations.
Environmental Monitoring	Environmental monitoring provides data/information about the actual environmental impacts of a Project. They are used to monitor compliance with environmental standards or any other discharges to the environment, and to facilitate any needed Project design or operational changes. Includes the cost of air quality, soil, water quality and wildlife monitoring systems to the extent required or stipulated by the provincial or federal agencies or as part of the Project approval.
Extraction / Tailings	Separation of hydrocarbons from their source and water from the sand and clay to enable incorporation of solids into reclamation landscapes and recycling of water back into the operations. Within the extraction and tailings facilities, this may include separators, froth treatment equipment, chemical handling and storage, water systems, steam systems, tumblers, primary separation vessels, analyzers and scales, naphtha, vapour and diluent recovery units, tailings oil recovery facilities, water reclamation, tailings distribution, pumps, control systems, etc. and buildings or shelters to house these facilities. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any "off project" buildings and structures directly attributable to the Project in accordance with the Regulations.
Gathering, Distribution & Storage	Gathering system means a pipeline or pipeline system, including installations and equipment associated with the pipeline or pipeline system, which transmits bitumen, solution gas used for Project operations and other oil sands products to a delivery point on Project lands. Includes all gathering systems, "in-Project" pipelines, bitumen storage and handling, water or steam distribution pipelines, power distribution systems, lighting systems, etc.

Strategic Capital	Capital expenditure to increase gross margin or decrease cost, e.g., through increased production capacity, product differentiation or reduced energy consumption.
Mining Equipment	Includes all facilities in the “mining” and “extraction” areas of a mine. This may include dams and water systems, tailings units including pumps and pipelines, retaining walls, ramps, dump pockets, breakers, crushers, cyclo-feeders, conveyor systems, scales, etc. within the “mine”. Also includes all “in-mine” trucks, heavy haulers, shovels, drag-lines, reclaimers, graders, crawler tractors, loaders, buses, etc. associated with mining operations. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any “off project” buildings and structures directly attributable to the Project in accordance with the Regulations. Includes all on or off-road vehicles, buses, snow clearing equipment, ski-doo’s, aircraft, helicopters, boats, barges, fuel trucks, fire protection equipment, etc. dedicated to the Project or allocated portions of similar equipment.
Reclamation & Abandonment	Activities for the stabilization, contouring, maintenance, conditioning or reconstruction of the surface of land resulting in the land being able to support a range of activities similar to its previous use before oil sands development. By law, industry must post financial security equivalent to the cost of reclamation before beginning oil sands activity. Funds provided to the Environmental Protection Security Fund as required by law and returned to industry when reclamation certificates are issued. Provide aggregated capital costs for reclamation and abandonment related assets.
Research	Costs for allowable in-house or third party research directly attributable to the Project as per the regulations. Costs to fund technology to solve a problem of immediate applicability to the particular Project, e.g., improving bitumen froth treatment in the Project facility; improving SAGD performance in a particular reservoir. **Note:** Any consideration received from the technology developed in the Project the cost of which were allowed costs in the Project must be included as other net proceeds.

Steam Generation & Distribution	Includes the cost of capital assets used solely for the purpose of generating steam for use in an OSR Project. The assets will be those between a boiler feed water metering facility at the inlet to the plant and the wellheads of all the steam injection wells on a Project. Steam plants may be located at a central facility or remotely located at various points within an approved OSR Project. Capital assets for steam generation within a co-generation facility are excluded from this category. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any “off project” buildings and structures directly attributable to the Project in accordance with the Regulations.
Sustaining Capital	Capital expenditure required to preserve the integrity of the asset, includes investment to mitigate once-off or recurring Health Safety Security Environment (HSSE) and reputation risks, HSSE investment required by law without which the unit/site would not have an operating license. Capital expenditures required to sustain production levels of the Project including costs for replacement production wells.
Transportation Infrastructure	Includes all Project roads, bridges, marine and air transportation infrastructure facilities, airstrips, hangers, docks, fixed radio, meteorological or navigation equipment, hangers, docks, but excluding vehicles, aircraft, helicopters, boats, barges, etc. Also includes all or an allowable portion of any “off project” transportation infrastructure required to access the Project.
Upgrading Facilities	The process that converts bitumen and heavy crude oil into a lighter crude oil by increasing the ratio of hydrogen to carbon, either by removing carbon (coking) or adding hydrogen (hydro-processing). Includes all bitumen processing (i.e., “upgrading”) equipment, “downstream” of the Extraction plant, intended to produce synthetic crude oil. Such equipment may include diluent recovery facilities, cokers, hydrogen units, hydro-treaters, sulphur units, sour water treaters, water systems, interconnecting piping, feed, chemical and product storage tanks, pumps and compressors, electrical equipment and distribution systems and buildings or shelters to house all such equipment. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any “off project” buildings and structures directly attributable to the Project in accordance with the Regulations.

Utility Plants (Mining)	Includes all plants providing "utility type" services to the Project including but not limited to raw water, treated and potable water, solid or liquid waste treatment, process steam, electricity, hydrogen, air, natural gas, syngas, etc. This category specifically excludes co-generation facilities whose costs must be reported separately. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any "off project" buildings and structures directly attributable to the Project in accordance with the Regulations. **Note:** For in-situ Projects this cost would be reported under the category "Emulsion Treating & Cleaning". In addition, for in-situ Projects that construct specific utility purpose facilities within the Project this cost should be segregated and reported in the "Other" cost category.
Water Treatment & Handling (In-Situ)	For in-situ Projects, include all costs associated with the sourcing, treatment, storage and distribution of water for the purpose of steam generation, water flood injection, potable water supply, etc. Includes the costs of any capital assets used to source the water and transport it to the OSR Project. Also includes all capital costs for water source facilities including wells. Includes all administration buildings, operations offices, on-site housing, cafeterias, recreation facilities, warehouses, training facilities, maintenance and fabrication shops, wash bays, emergency services buildings, permanent camps, etc. May also include all or an allowable portion of any "off project" buildings and structures directly attributable to the Project in accordance with the Regulations.
OPERATING COST DEFINITIONS	
Cleaning Emulsion & Water Treatment Activity – Thermal Production	The separation of water and bitumen emulsion into components for further treating or upgrading. Treatment process includes separation of gas and other substances, such as sand, from the production stream and may also include blending within the treatment process.
Cleaning Emulsion Activity – Cold Production	The separation of water and bitumen emulsion into components for further treating or upgrading. Treatment process includes separation of gas and other substances, such as sand, from the production stream and may also include blending within the treatment process.
Contracted Services	Provide the total costs of all third party contracted services including the costs of labour, hardware, software, equipment (excluding long term equipment rentals/leases identified below), professional services, performance inducements, bonuses, etc. for all contracts. Includes aggregate costs for third party provided utilities including services as water, sewer, compressed air and communications.
Energy – Other	Provide the cost of any other purchased energy (e.g., hydrogen, steam, etc.) consumed on the Project and includes the provision of non-arm's length supplied energy commodities.

Environmental Levies	Payments to local governments for the specific purpose of funding environmental protection and natural resource management projects within the local government area.
Equipment Rentals	Provide aggregated costs associated with equipment rentals or leases.
Extraction / Tailings Activity	Separation of hydrocarbons from their source and water from the sand and clay to enable incorporation of solids into reclamation landscapes and recycling of water back into the operations.
Labour Compensation Off-Site – Direct	Direct Labour Costs defined as costs specifically tracked and assigned to a function or facility incurred off-site the Project. Provide total compensation costs for all Project employees including salaries, benefits, bonuses, stock options and any other form(s) of remuneration whether fixed or variable.
Labour Compensation Off-Site - Shared	Provide total costs for all supplied corporate services, such as engineering, marketing, accounting, legal, human resources, etc. whose time is directly attributable to the Project and are incurred off-site of the Project. Costs include compensation (salaries, benefits, bonuses, stock options and any other form(s) of remuneration whether fixed or variable).
Labour Compensation On-Site – Direct	Direct Labour Costs defined as cost specifically tracked and assigned to a function or facility incurred on-site of the Project. Provide total compensation costs for all Project employees including salaries, benefits, bonuses, stock options and any other form(s) of remuneration whether fixed or variable.
Labour Compensation On-Site - Shared	Provide total costs for all supplied corporate type services, such as engineering, marketing, accounting, legal, human resources, etc. whose time is directly attributable to the Project and are incurred on-site the Project. Costs include compensation (salaries, benefits, bonuses, stock options and any other form(s) of remuneration whether fixed or variable). Shared Labour Costs defined as costs that are accumulated in a general labour pool and prorated to a function or facility based on a percentage basis.
Mining Activity	Mining is the recovery of oil sands from the ore body.
Municipal/Provincial Taxes & Fees	Includes the aggregate of all taxes and fees paid to municipal and provincial governments.
Processing Fees (Non-Arm's Length)	Includes the cost of all fees paid to non-arm's length parties for processing oil sands products.

Processing Fees (Third Party)	Includes the cost of all fees paid to third parties for processing oil sands products.
Purchased Energy - Electricity	Provide the cost of all purchased electricity consumed in the Project.
Purchased Energy – Natural Gas	Provide the cost of all purchased natural gas consumed in the Project. This includes solution gas "deemed to be sold from one Project to another for consumption purposes so the receiving Project has a purchase cost."
Purchased Feedstock (Non-Arm's Length)	Include the cost of all bitumen, or any other oil sands products, purchased from non-arm's length parties for processing within the Project.
Purchased Feedstock (Third Party)	Include the cost of all bitumen, or any other oil sands products, purchased from others for processing within the Project.
Steam Generation Activity	A boiler or steam generator used to create steam by applying heat energy to water.
Supplies & Materials	Provide costs for all supplies and materials purchased for the Project, including but not limited to chemicals, injectants, transportation fuels, office and administrative supplies, cleaning supplies, spare parts, maintenance items, etc.
Upgrading / DRU Activity	All operating costs associated with upgrading bitumen to synthetic crude oil. Diluent Recovery Unit is an operating unit for solvent or diluent recovery from oil sand product streams.
Utilities (UO/ES) Activity	The activity of supplying an energy source to be consumed in approved oil sands processes.
Well Operations Activity (Including Delineation & Development)	All costs related to the operation of a producing, observation, injecting, source and disposal wells.

VOLUMETRIC DATA	
Note: Reporting on the Volumetric form is on a Project basis and not on an equity basis if more than one joint venture participant.	
Bitumen	The principal hydrocarbon resource produced from an OSR Project in designated oil sands areas. Measured in m^3. **Note:** On this form for volumetric data pertaining to bitumen, third party volumes means any volumes that do not originate at the OSR Project.
Coke	One of the products of a thermal cracking process used to convert long chain bitumen hydrocarbon into shorter chain gases and gas oils coke. Coke is a material that is essentially pure carbon. Measured in tonnes.
Consumed	A product utilized or expended in an approved oil sands process.
Delivered to the Royalty Calculation Point (RCP)	As defined in OSRR09, Part 4, Division 2, Section 30.
Diluent	A hydrocarbon fluid that is used to dilute bitumen and heavy oil so as to reduce its viscosity for easier transportation. Measured in m^3.
Electricity	Electricity may be generated on a Project site, normally using gas fired generators, or from a co-generation plant where steam is also produced. It may also be purchased from or sold to a third party through an electrical power transmission grid. Measured in KWh.
CO_2 - Green House Gas (GHG) Emissions	Greenhouse Gas Emission: Release of CO_2 equivalent based on the sum of direct emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydro fluorocarbons (HFC), per fluorocarbons (PFC), and sulphur hexafluoride (SF_6). Measured in ktonnes.
Heavy Minerals	Heavy minerals include typically zirconium, titanium, thorium, tungsten and rare earth elements. Measured in kg.
Natural Gas	Naturally occurring mixtures of hydrocarbon gases and vapours, mostly methane (CH_4) and may be used as a thermal energy source or as a source of hydrogen for various hydro-treating processes. **Note:** This included solution gas as defined in OSRR09, Part 1, Section 1(1)(rr). Measured in 10^3m^3.
Overburden	Overburden refers to the material that lies above the area of economic interest (i.e., the rock and soil that lies above the oil sands deposit). Overburden is removed during surface mining and is typically stored to be later used in reclamation to restore a mining site to a semblance

	of its condition before mining began. Measured in banked cubic metres.
Processed	Processing means the action of creating new product(s) from existing product(s) by: - Extracting component gases and/or liquids from a product; - Combining two or more products; and - Altering the state in which a product exists, i.e., changing a product from a solid state to a liquid state.
Produced	Produced means unsold, unprocessed substance composed of products recovered from a formation, which originates at the first point of separation/measurement after the wellhead or surface and ends at the next processing point.
Purchased	A product or service purchased for use in an approved oil sands process.
Solvents	Solvents are fluids, capable of dissolving with the oil they contact, injected into a reservoir to form a single liquid that can move through the reservoir to a producing well more easily than the original crude oil. Measured in m^3.
Steam	Steam refers simply to vaporized water. It is a two-phase mixture of liquid water and steam produced from a generator or boiler. Higher quality steam has higher vapour content. In thermal recovery operations, it is injected into reservoirs to reduce the viscosity of the bitumen so it will flow more easily to a producing well bore or to provide heat to a variety of processing plants. Measured in tonnes/day and reported in cold water equivalent (CWE) m^3. Steam is measured in the number of metres cubed of cold water that will be vaporized to generate the steam.
Sulphur	Elemental sulphur is produced from a process to remove hydrogen sulphide from produced hydrocarbons including bitumen, heavy oil and solution gas. It may be shipped to market in liquid or solid form or, due to ongoing limited markets and low prices, is often stored by pouring molten sulphur into large solid blocks pending its sale. Measured in tonnes.
Synthetic Crude Oil	A mixture mainly of pentanes and heavier hydrocarbons which may also contain sulphur compounds that is derived from crude bitumen and is liquid at the conditions under which its volume is measured. The output of a process employed to “upgrade” (through the addition of hydrogen or the rejection of carbon) bitumen into a marketable product as feedstock for multiple downstream refineries. Measured in m^3.
Tailings	

	Tailings are the waste material from the Extraction Plant in an oil sands mining operation. Tailings are principally water but contain significant amounts of clay, residual hydrocarbon, heavy metals and other impurities. Measured in m^3.
Water	In the context of an OSR Project, it may refer to ground water, produced water, surface fresh water, processed or treated water, waste water, etc. Measured in m^3.
OPERATIONS DATA	
CO_2 Capture	The total amount of CO_2 captured and shipped to an approved “sequestration” project or facility which utilizes or further processes the CO_2 such that it is not released into the atmosphere.
CO_2 Emissions	The calculated total amount of CO_2 emissions from the OSR Project in tonnes per year as required by the mandatory GHG reporting initiative started in 2004.
NO_x Emissions	The total amount of Nitrogen Oxides emissions in annual average tonnes per day from all sources within the OSR Project.
Number of Site Staff (Full Time Equivalency – FTE)	The total number of operator employed permanent staff whose principal place of work is at the OSR Project and whose compensation is charged to the Project as a component of the “operating cost”.
SO_2 Emissions	The total amount of sulphur dioxide emissions in annual average tonnes per day from all sources within the OSR Project.
Water Recycle Rate	The amount of process water that is recycled as a percentage of total water used in a Project. Water Recycle Rate (%) = ((Total process water used in the Project – make up water added to the Project) / Total process water used in the Project) x 100
DEPOSIT & RESERVOIR DATA	
Bitumen Density	A measure of the mass of a substance per unit of volume (i.e., kg/m^3) the mass occupies, usually reported at standard temperature and pressure (STP). For bitumen, the density measurement is the value derived from a representative bitumen sample that has been prepared and measured according to generally accepted standard practices (i.e., ASTM4052).
Bitumen Viscosity	Viscosity is a measure of the resistance of a fluid to flow and normally measured in centipoises (“cP”). It is commonly perceived as "thickness".

Deposit Thickness	Provide the weighted average thickness of the recoverable oil sands deposit within the OSR Project.
Depth to Top of Deposit	The distance from the top of the oil sands deposit to the surface measured in metres.
Mine Area	The total expected surface area of the mine, excluding any sterilized area, measured in metres squared.
Oil Grade	The determination of the amount of bitumen within the oil sands deposit. Low grade – approximately 8% bitumen Medium grade - approximately 10% bitumen High grade - approximately 13% bitumen
Oil Saturation	The measurement of the fraction, or percentage of the total pore volume of the reservoir occupied by bitumen. Measured as a percentage.
Original Bitumen in Place (OBIP)	The original oil in place is the total hydrocarbon content of an oil reservoir before the commencement of production. Oil in place should not be confused with oil “reserves” that are the technically and economically recoverable portion of it. Provide the calculated OBIP for the producing horizon within the area as defined by the operator.
Permeability - Horizontal	The measure of ease with which a fluid flows in a horizontal direction through the connected pore space of a reservoir rock ability typically measured in Darcie’s or milliDarcies. Permeability should be measured as the absolute permeability using 100 percent saturation of a liquid (brine) in the reservoir. Provide a weighted average permeability of the bitumen producing zone within the OSR Project. Average – weighted average permeability of the bitumen producing zone within the OSR Project. Range – range across the Project area
Permeability – Vertical	The measure of ease with which a fluid flows in a vertical direction through the connected pore space of a reservoir rock ability typically measured in Darcie’s or milliDarcies. Permeability should be measured as the absolute permeability using 100 percent saturation of a liquid (brine) in the reservoir. Average – weighted average permeability of the bitumen producing zone within the OSR Project. *Range* – range across the Project area
Porosity	The percentage of pore volume or void space that can contain fluids. Provide a weighted average porosity of the producing zone within the OSR Project.

Reservoir Area	The area used to determine the bulk volume of crude bitumen deposit measured in m^2: - For land based approvals, the reservoir area is the entire royalty Project area. - For well based approvals, the reservoir area is the well drainage area.
Reservoir Depth	Provide the weighted average depth from surface to the top of the producing zone within the OSR Project.
Reservoir Net Pay	Defined as the thickness of the porous, permeable interval of the reservoir containing oil sands reserves which are anticipated to be economically recoverable. Calculated as the weighted average reservoir net pay over the entire OSR Project area.
Reservoir Pressure - Initial	The initial reservoir pressure at the reference elevation of a pool upon discovery.
Reservoir Temperature - Initial	The initial reservoir temperature at the reference elevation of a pool upon discovery.
Reservoir Thickness	Calculated as the weighted average thickness of the oil sands zone over the entire OSR Project area.
RESERVES DATA	
Initial Proven Reserves	Defined in either COGEH or SPE - PRMS as bitumen reserves within the company defined Project area having a "high degree of certainty" (90% probability) of being produced using current technology at current prices, with current commercial and regulatory terms and conditions prior to first production at inception of the OSR Project application. For OSR Projects approved prior to June 30, 2009, operators may determine the “As at Date” to provide the DOE with a historical date. Operator defined date must be December 31, 2008 or earlier. **Note:** Report gross reserves calculated prior to royalty determination.
Initial Proven + Probable Reserves	Defined in either COGEH or SPE - PRMS as bitumen reserves within the company defined Project area that is reasonably probable (50% probability) of being produced using current or likely technology at current prices, with current commercial and regulatory terms and conditions prior to first production at inception of the OSR Project application. For OS Projects approved prior to June 30, 2009, operators may determine the “As at Date” to provide the DOE with a historical date. Operator defined date must be December 31, 2008 or earlier. **Note**: Report gross reserves calculated prior to royalty determination.

Methodology Used to Determine Reserves	Canadian Oil and Gas Evaluation Handbook (COGEH) Society of Petroleum Engineers –Petroleum Resource Management System (SPE-PRMS)
Project Area	Defined as the area consistent with the operator's current life plan for the Project. Identify all OSR Project(s), AER Approved Project Area(s) and Approved OS leases. Plat style map to be submitted to depict operator's definition of Project area with corresponding township, range and section.
Remaining Proven Reserves	Defined in either COGEH or SPE - PRMS as remaining bitumen reserves within the company defined Project area having a "high degree of certainty" (90% probability) of being produced using current technology at current prices, with current commercial and regulatory terms and conditions as of December 31 of the previous calendar date. **Note**: Report gross reserves calculated prior to royalty determination.
Remaining Proven + Probable Reserves	Defined in either COGEH or SPE - PRMS as remaining bitumen reserves within the company defined Project area that is reasonably probable (50% probability)of being produced using current or likely technology at current prices, with current commercial and regulatory terms and conditions as of December 31 of the previous calendar date. **Note**: Report gross reserves calculated prior to royalty determination.
REVENUE REPORTING	
COVER PAGE	
Cleaned Crude Bitumen	Crude bitumen from which impurities have been removed sufficiently to allow it, when blended with diluent, to be transported by pipeline or truck or any other means of transportation.
Density (Cleaned Crude Bitumen)	Bitumen Density – a measure of the mass of a substance per unit of volume (i.e., kg/m^3) the mass occupies, usually reported at standard temperature and pressure (STP). For bitumen, the density measurement is the value derived from a representative bitumen sample that has been prepared and measured according to generally accepted standard practices (i.e., ASTM4052).
Sulphur Content (Cleaned Crude Bitumen)	The amount of sulphur, as a percentage of volume, contained within the cleaned crude bitumen at the royalty calculation point. Measured as a percentage of volume (i.e., (sulphur m^3/bitumen stream m^3) x 100% = sulphur %).
Stream Name	Bitumen blend that comes from a specific area with a consistent quality or bitumen that comes from a heated pipeline. Choose the "Stream Name" from the drop down. If the "Stream Name" does not appear in the drop down menu, use "Other Stream" and enter the name in the "If Other Stream" cell. If the moniker changes before it reaches the Point of Sale, please specify the new moniker in the notes section and contact the Department for a Secondary Blend Revenue form.

REVENUE REPORTING	
BITUMEN/BITUMEN BLEND REVENUE	
Arm's Length Transactions	Where an operator sells goods and/or services to an entity with whom the operator is not affiliated, these transactions are considered arm's length, as defined by the *Oil Sands Royalty Regulation, 2009*.
Handling Charge	As defined under the Regulation, the cost to transport the oil sands product from the RCP to a sales point relating to sales volumes sold in that month and reported on the GFE or MRC. Such costs may include prorated pooled costs relating to cost of service for use of the pipeline and pipeline tariffs and trucking costs incurred. **Note:** Enter one monthly total for all Arms' Length Volumes transacted in the month and one monthly total for all Non Arms' Length Volumes transacted in the month for the stream, irrespective of Point of Sale.
Month of Sale	The month in which the transfer of title occurs.
Non-Arm's Length Transactions	Where an operator sells goods and/or services to an entity with whom the operator is affiliated, these transactions would be considered as non-arm's length, as defined in the *Oil Sands Royalty Regulation, 2009.*
Point of Sale	The location where the title transfer of the product occurs. If the transfer occurs in Canada, identify the hub or terminal. If title transfer occurs in the US, identify the State and Petroleum Administration Defense District (PADD).
Product Type	Bitumen or blended bitumen. Dilbit - Dilbit is a syllabic abbreviation of 'diluted bitumen.' The bitumen has been blended with condensate or naphtha or other types of diluents excluding synthetic crude oil. SynBit - Bitumen has been blended with synthetic crude oil. SynDilBit – The bitumen that has been blended with synthetic crude oil and condensate.
Product Volumes	Bitumen blend stream volumes sold as measured in cubic metre. Identify in the footnote section whether the sales volumes contain oil sands sales volumes subject to conventional royalty calculations (NPR). Enter volumes sold at Arm's Length and Non-Arm's Length transactions.

Product Price	The consideration received in Canadian dollars per cubic metre for the blended bitumen stream volumes sold. If multiple sales occur at the same point of sale then report the weighted average price. For each Point of Sale, enter Product Prices for volumes sold at Arm's Length and Non-Arm's Length transactions.
BITUMEN BLEND NETBACK CALCULATION	
Blend Volume	Identify the volume of bitumen blend crossing the RCP. Report the volume in cubic metre.
Diluent Sent back to Project	Identify if the diluent was sent back to the OSR Project or to the diluent pool outside the OSR ring fence. Report "Yes" or "No" in the field.
Diluent Type	The type of diluent blended with the bitumen to meet pipeline specifications. E.g., butane, condensate, synthetic crude oil etc. Use drop down menu to select Diluent Type. If the Diluent Type does not appear in the drop down list choose Other, and enter the Diluent Type in the Notes section.
Diluent Volume	Diluent Volume is the volume of diluent (per diluent type) in the bitumen blend crossing the RCP. Report the volume in cubic metre. If diluent is added after the RCP yet before the Point of Sale, assume that the diluent is added at the RCP.
Diluent Price	The price of diluent (per diluent type) used in the bitumen blend. If pooled diluent is used then the weighted average price should be reported.
Month of Sale	The month in which the transfer of title occurs.
Shrinkage Volume	Identify the shrinkage volume resulting from the blending of hydrocarbons with disparate densities. Report the volume in cubic metre.

DILUENT SUPPLIED TO PROJECT – IN-SITU PROJECTS	
Arm's Length Transactions	Where an operator acquires goods and/or services from an entity with whom the operator is not affiliated, as defined by the *Oil Sands Royalty Regulation, 2009*. **Note:** Enter the diluent volume supplied at Arm's Length as a percentage of total diluent volume supplied.
Non-Arm's Length Transactions	Where an operator acquires goods and/or services from an entity with whom the operator is affiliated, as defined by the *Oil Sands Royalty Regulation, 2009*, these are non-arm's length transactions.
Diluent Pool Location	The location where the diluent is injected into the diluent pool. The physical location of the diluent pool where the weighted average price (WAP) is calculated for application to the OSR Project. If referencing a pipeline, add the location of the pipeline.
Diluent Density	Density is defined as the mass of a substance per unit volume. Provide the diluents density in kg/m3. If diluent is pooled, identify the blended density of the diluent.
Diluent Type	The type of diluent blended with the bitumen to meet pipeline specifications. E.g., butane, condensate, synthetic crude oil.
Mode of Transportation	The method of transporting the diluent product to the OSR Project. Report pipeline or trucking or any other means of transportation on separate lines.
Month of Supply	The month in which the transfer of title occurs.
Diluent Price	The diluent purchased price in Canadian dollars per cubic metre. If diluent is pooled, report the weighted average price.
Transportation Costs	Costs associated with transporting diluent from the diluent pool location, where the weighted average price (WAP) calculation is triggered, to the OSR Project. If the diluent price includes the transportation cost, input "Included".
Volume	Volume of diluent from the diluent pool that goes to the OSR Project. Report volumes in cubic metre. This does not have to match with the GFE/MRC-1 forms.

TRANSPORTATION COSTS – IN-SITU PROJECTS	
Destination	For each mode of transportation, identify the point where the product was unloaded, reaches a Canadian hub or reaches its title transfer point. For Canadian hub, identify (e.g., Hardisty or Edmonton). For US destinations, identify State and Petroleum Administration Defense District (PADD).
Includes Diluent Return	Indicate with Yes or No whether diluent return line costs are included in the transportation costs.
Mode of Transportation	The method of transporting the sales product from RCP to the title transfer point of sale. Report pipeline, rail or trucking on separate lines.
Month	The month in which the transportation costs are incurred.
Origin	For initial transportation identify the OS Project area (e.g., Cold Lake, Wabasca, Peace River, etc.) If the title transfer occurs in the US, identify the Canadian hub (e.g., Hardisty or Edmonton).
Product	Bitumen or blended bitumen. Dilbit - Dilbit is a syllabic abbreviation of 'diluted bitumen'. The bitumen has been blended with condensate or naphtha or other types of diluents excluding synthetic crude oil. SynBit - The bitumen has been blended with synthetic crude oil. SynDilBit – The bitumen that has been blended with synthetic crude oil and condensate.
Stream	Bitumen blend that comes from a specific area with a consistent quality or bitumen that comes from a heated pipeline (LLE). Example: Cold Lake Blend (CLB) Peace River Blend (PRB)
Volumes Transported	Actual transported volumes from the origin to the destination. Measured in cubic metre and based on product movement.
Transportation Cost	Aggregated transportation costs based on actual invoices or cost of service and product movement related to a title transfer location. If the title transfer occurs in the US, the costs must be disaggregated into a Canadian component and an US component. (I.e., Aggregate costs from the OSR Project location to a Canadian hub and from the Canadian hub to the US State/PADD).

OTHER OIL SANDS PRODUCTS REVENUE – MINING & IN-SITU PROJECTS	
Arm's Length Transactions	Where an operator sells goods and/or services to an entity with which the operator is not affiliated, as defined by the *Oil Sands Royalty Regulation, 2009.*
Non-Arm's Length Transactions	Where an operator sells goods and/or services to an entity with which the operator is affiliated according to the *Oil Sands Royalty Regulation, 2009*.
Destination	The location where the title transfer of the product occurs.
Mode of Transportation	The method of transporting the sales product from RCP to the title transfer point of sale. Report pipeline, rail or trucking on separate lines.
Month of Sale	The month in which transfer of title occurs.
Other Handling Costs	Costs other than transportation that are incurred to move the product to the destination.
Price	Price per other oil sands product type in Canadian dollars per product unit.
Other Oil Sands Product	As defined in the Regulation. Examples include coke, sulphur (excluding sulphur from solution gas) etc.
Transportation Cost	Cost incurred to transfer the product from the OSR Project to the destination (title transfer point) in Canadian dollars.
Volume	Volume of the Other Oil Sands Product. State specific product unit.

Appendix E

CARE – Timeline and Timetable

<table>
<tr><td colspan="3">Capital and Operating costs are filed on a year to date basis. Amendments to these forms can be trued up in the next quarter’s filing or with the last quarter filing where reconciliation to the End of Period Statements (EOPS) is required. Amendments to all other forms are full form replacement and should not be trued up in the last quarter but amended in the quarter the changes relate.</td></tr>
<tr><th>CARE Spreadsheet</th><th>Frequency</th><th>Filing Requirement</th></tr>
<tr><td>CARE – Cost Workbooks for both
In-Situ and Mining

(Allowed Cost/EOPS Reconciliation,
Capital and Operating Costs)</td><td>Quarterly -
Year to Date and Detailed by Month</td><td>1^{st} Qtr – May 20
2^{nd} Qtr – Aug 20
3^{rd} Qtr – Nov 20
4^{th} Qtr – April 30
of the following year</td></tr>
<tr><td>CARE – Revenue Workbook</td><td>Quarterly -
Year to Date and Detailed by Month</td><td>1^{st} Qtr – May 20
2^{nd} Qtr – Aug 20
3^{rd} Qtr – Nov 20
4^{th} Qtr – Feb 20
of the following year</td></tr>
<tr><td>CARE – Project Data Workbook for both
In-Situ and Mining

(Reserves, Operations, Reservoir, Deposit and Volumetric reporting)</td><td>Annually -
Year to Date</td><td>June 30^{th} of the following year</td></tr>
<tr><td>Western Canadian Select Revenue</td><td>Quarterly -
Year to Date and Detailed by Month</td><td>1^{st} Qtr – May 20
2^{nd} Qtr – Aug 20
3^{rd} Qtr – Nov 20
4^{th} Qtr – Feb 20
of the following year</td></tr>
<tr><td>CARE –
Statement of Approval</td><td>Quarterly or Annually (dependent on workbook)</td><td>For CARE – COSTS & REVENUE Workbooks:
1^{st} Qtr - May 20^{th} of the period
2^{nd} Qtr - Aug 20^{h} of the period
3^{rd} Qtr - Nov 20^{th} of the period
4^{th} Qtr - Feb 20^{th} of the period
(REVENUE Workbook)
4^{th} Qtr - April 30th of the following year
(COSTS Workbook)
For CARE – PROJECT Workbook:
Due June 30^{th} following the Period</td></tr>
</table>

Appendix F

Abbreviations Used in Guidelines

AFE	Authorization for Expenditure
AER	Alberta Energy Regulator
BVM	Bitumen Valuation Methodology
BVMR	Bitumen Valuation Methodology (Ministerial) Regulation
CAPP	Canadian Association of Petroleum Producers
CARE	Cost Analysis and Reporting Enhancement
CHP	Combined Heat and Power
CRW	standard condensate stream
COS	Cost of Service
EOPS	End of Period Statements
ETS	Electronic Transfer System
FCP	Fuel Charged to Power
FCS	Fuel Charged to Steam
FMV	Fair Market Value
GFE	Good Faith Estimate
HRSG	Heat Recovery Steam Generator
LTBR	Long-Term Bond Rate
MRC	Monthly Royalty Calculation
NAL	Non-Arm's Length
OSAC	Oil Sands Allowed Cost (Ministerial) Regulation
OSR	Oil Sands Royalty
OSRR09	Oil Sands Royalty Regulation, 2009
PNCB	Prior Net Cumulative Balance
RCP	Royalty Calculation Point
RORC	Rate of Return On Capital
SAGD	Steam Assisted Gravity Drainage
SCO	Synthetic Crude Oil

TA	Transportation Allowance
TAN	Total Acid Number
TPDT	Third Party Disposition Threshold
WCS	Western Canadian Select
WTI	West Texas Intermediate

Appendix G

Contact Information

Mailing Address (Edmonton)	Mailing Address (Calgary)
Resource Development Policy Division	Resource Revenue and Operations Division
Alberta Energy	Alberta Energy
North Petroleum Plaza	300, 801 - 6^{th} Avenue SW
9945 - 108 St	Calgary, Alberta Canada
Edmonton, Alberta Canada	T2P 3W2
T5K 2G6	

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For more information about this document and about Alberta's oil sands royalty regime, please go to Alberta Energy website at <www.energy.gov.ab.ca> under 'Our Business', 'Oil Sands', then 'Oil Sands Contacts' or contact the following Alberta Energy staff:

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Queen's Printer Bookstore
602 620 – 7 Avenue SW
Calgary, Alberta T2P 0Y8
Phone: 403 297-7157

Or

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10611 – 98 Avenue
Edmonton, Alberta T5K 2P7
Phone: 780 427-4952
Fax: 780 452-0668

Also available on-line at: http://www.qp.gov.ab.ca

CIBC Rapidtrans (royalty payment) deposit slips

Alberta Energy
Calgary Information Centre
300, 801 - 6th Avenue SW
Calgary, Alberta T2P 3W2
Phone: 403 297-8955
Fax: 403 297-8954

Payment and Payment Allocation Inquiries
Financial Services (Cashiers)
Alberta Energy
Financial Services Branch
North Petroleum Plaza
9945 - 108th Street
Edmonton, Alberta T3K 2G6
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Appendix H

Electronic Transfer System (ETS) - File Naming Conventions

For CARE and Operator's Forecast Report Submissions in ETS Correspondence

NOTE1: Ensure that access has been granted to the submissions below by your company ETS Site Administrator otherwise these will not appear in the Form Type drop down selection list in ETS Correspondence.

NOTE2: Project Number can be OSR### or CSR###, Stream Abbreviation can be a maximum of 10 characters, use MULT as abbreviation if there is more than one stream in the report, version number for the original submission is V1 and is advanced by one with each subsequent amendment

Effective 2011 to 2014 Reporting Periods		
Submission Type	**File Naming Convention**	**Example**
CARE Project Workbook	<Project Number>_<Year>_PROJECT_V<#>	OSR123_2011_PROJECT_V1.xlsx
CARE Cost In Situ Workbook	<Project Number>_<Year>_QTR<#>_COSTS (IS)_V<#>	OSR123_2011_QTR3_COSTS(IS)_V1.xlsx
CARE Cost Mining Workbook	<Project Number>_<Year>_QTR<#>_COSTS (M)_V<#>	OSR123_2011_QTR3_COSTS(M)_V1.xlsx
CARE Revenue Workbook	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_REVENUE_V<#>	ABC_0A6K5_LLE_2011_QTR1_REVENUE_V1.xlsx
CARE Western Canadian Select (WCS) Sales	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_WCSS_V<#>	ABC_0A6K5_LLE_2011_QTR1_WCSS_V1.xlsx
Effective 2009 and 2010 Reporting Periods		
Submission Type	**File Naming Convention**	**Example**
Volumetric Data (Integrated) Mining and In Situ	<Project Number>_<Year>_VOLINT_V<#>	OSR123_2009_VOLINT_V1.xlsx
Volumetric Data (Non-Integrated) Mining and In Situ	<Project Number>_<Year>_VOLNINT_V<#>	OSR123_2009_VOLNINT_V1.xlsx
Operations Data – Mining and In Situ	<Project Number>_<Year>_OPER_V<#>	OSR123_2009_OPER_V1.xlsx
Deposit Data - Mining	<Project Number>_<Year>_DPST(M)_V<#>	OSR123_2009_DPST(M)_V1.xlsx
Reservoir Data – In Situ	<Project Number>_<Year>_RSVR(IS)_V<#>	OSR123_2009_RSVR(IS)_V1.xlsx
Reserves Data – Mining and In Situ	<Project Number>_<Year>_RESERVES_V<#>	OSR123_2009_RESERVES_V1.xlsx
Operating Costs - Mining	<Project Number>_<Year>_<#>QTR_OPEX(M)_V<#>	OSR123_2009_2QTR_OPEX(M)_V1.xlsx

Operating Costs – In Situ	<Project Number>_<Year>_<#>QTR_OPEX(IS)_V<#>	OSR123_2009_2QTR_OPEX(IS)_V1.xlsx
Capital Costs - Mining	<Project Number>_<Year>_<#>QTR_CAPEX(M)_V<#>	OSR123_2009_2QTR_CAPEX(M)_V1.xlsx
Capital Costs – In Situ	<Project Number>_<Year>_<#>QTR_CAPEX(IS)_V<#>	OSR123_2009_2QTR_CAPEX(IS)_V1.xlsx
Bitumen/Bitumen Blend Revenue – In Situ Projects	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_BLENDREV_V<#>	ABC_0A6K5_LLE_2011_QTR1_BLENDREV_V1.xlsx
Bitumen Blend Net Calculation – In Situ Projects	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_NETBKCAL_V<#>	ABC_0A6K5_LLE_2011_QTR1_NETBKCAL_V1.xlsx
Transportation Costs – In Situ Projects	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_TRANSCST_V<#>	ABC_0A6K5_LLE_2011_QTR1_TRANSCST_V1.xlsx
Diluent Supplied to Stream – In Situ Projects	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_DILUENT_V<#>	ABC_0A6K5_LLE_2011_QTR1_DILUENT_V1.xlsx
Other Oil Sands Products Revenue – Mining and In Situ Projects	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_OOSPREV_V<#>	ABC_0A6K5_LLE_2011_QTR1_OOSPREV_V1.xlsx
Western Canadian Select (WCS) Sales	<Company Name>_<BA ID>_<Stream Abbreviation>_<Year>_QTR<#>_WCSS_V<#>	ABC_0A6K5_LLE_2011_QTR1_WCSS_V1.xlsx
Effective All Reporting Periods		
Submission Type	**File Naming Convention**	**Example**
Operator's Forecast	<Project Number>_<Year>_OPERATORS_FORECAST_V<#>	OSR123_2009_OPERATORS_FORECAST_V1.xlsx

Appendix I

Oil Sands Royalty Project Reporting Interest Rules

Type of Royalty Compensation	Interest OSRR09 Section	EOPS Filed	Report Due Date	Due Date Payment or Refund	Interest Calculated	Interest Rate	Effective Date of Interest Calculation
Pre-Payout Projects OSRR09							
MRC Underpayment (same rules apply before or after EOP due date)	s.45(1)(a) and s.45(1)(c)	N/A	Last day of the month following the month for which the report is required.	Last day of the month following the month for which the report is required.	Simple Daily Interest Compounded Monthly	Prime+1%	1st day after MRC payment due date until the amount is paid to the Minister.
MRC Overpayment	No Provisions	N/A	Last day of the month following the month for which the report is required.	No Provisions	N/A	N/A	N/A
Post-Payout Projects OSRR09							
Missing GFE Installment (Underpayment)	s.45(1)(a) s.45 (1)(c)	N/A	Last day of the month following the month for which the report is required.	Last day of the month following the month for which the report is required.	Simple Daily Interest Compounded Monthly	Prime + 1%	1st day after the GFE installment payment due date until the amount is paid to the Minister.
EOPS Payable (underpayment) and Royalty Adj. **>10%** (Includes both Operator submitted EOP and Audit Adjustments)	s.45(1)(d) s.45(2)(a) s.45(2)(b) s.45(2.1) and s.45(3)	Yes	Last day of the 3rd month following the Period.	Last day of the 4th month following the Period.	Simple Daily Interest Compounded Monthly	Prime+1%	• If the period comprises a dull calendar year, commencing on July 1 of that Period. • If the Period is less than a full calendar year, coming on the day following the half-way point of the Period (“Half- Period rule”) Until the amount is paid to the Minister.

Type of Royalty Compensation	Interest OSRR09 Section	EOPS Filed	Report Due Date	Due Date Payment or Refund	Interest Calculated	Interest Rate	Effective Date of Interest Calculation
EOPS Payable (underpayment) and Royalty Adj. <=**10%** (Includes both Operator submitted EOP and Audit Adjustments)	s.45(1)(d) s.45(2)(a) s.45(2)(b) and s.45(3)	Yes	Last day of the 3rd month following the Period.	Last day of the 4th month following the Period.	Simple Daily Interest Compounded Monthly	Prime+1%	Commencing the day following the last day of the 4th month following the Period until the amount is paid to the Minister.
EOPS Refund (overpayment)	s.45(6)(b)	Yes	Last day of the 3rd month following the Period.	Last day of the 4th month following the Period.	Simple Daily Interest	Prime+1%	Commencing from the last day of the 4th month following the Period for which the overpayment relates to the date of the cheque requisition or the Minister notifies the operator
Large GFE Installment Overpayment	s.45(6)(a)	Yes	Last day of the month following the month for which the report is required.	Last day of the month following the month in which the report is provided	Simple Daily Interest	Prime+1%	Commencing from the day following the last day of the Period to the date of the cheque requisition or the Minister notifies.
Non-project OSRR09							
Monthly royalty underpayment	s.45(1)(a)	N/A	Last day of the month following the month for which the report is required.	Last day of the month following the production month	Simple Daily Interest Compounded Monthly	Prime+1%	1st day after the payment due date until the amount is paid to the Minister.
Effective 2017 - Amended OSRR09							
Overpayment of a disputed amount	s.45(6)(b.1) s.45(6.01)	N/A	N/A	Last day of the month in which the operator paid the disputed amount	Simple Daily Interest	Prime+1%	Commencing from the day following the last day of the month in which the operator paid the disputed amount to the date of the cheque requisition or the notification date to the operator

Type of Royalty Compensation	Interest OSRR09 Section	EOPS Filed	Report Due Date	Due Date Payment or Refund	Interest Calculated	Interest Rate	Effective Date of Interest Calculation
Overpayment (includes both Operator submitted amendments and Audit Adjustments)	s.45(6)(d) and s.45(6.1)	N/A	Last day of the month following the month for which the report is required.	By the due date (the day before the interest commencement date)	Simple Daily Interest	Prime+1%	Commencing the first day of the 2nd month following the month in which the operator is notified by the Minister of the results of the recalculation pursuant to which the overpayment arose (for audit adjustments) or the operator provides notice to the Minister of the overpayment (for amendments filed by the Operator) whichever occurs first, until the requisition of a cheque or the Minister notifies the operator to deduct the amount from an amount required to be paid.
Provisional Royalty Compensation (for OSR Projects and non-Project well events) OSRR09							
Underpayment (provisional royalty compensation)	s.45(1)(a)	N/A	N/A	By the end of the month following the month in which the Minister issues an invoice	Simple Daily Interest Compounded Monthly	Prime+1%	Commencing the first day of the second month following the month in which the Minister issues an invoice to the operator for the amount until the requisition of a cheque.
Overpayment (provisional royalty compensation)	No Provisions	N/A	N/A				
Underpayment (provisional royalty compensation recalculation)	s.45(1)(a)	N/A	N/A	By the end of the month following the month in which the operator is notified of the results of the recalculation.	Simply Daily Interest Compounded Monthly	Prime+1%	Commencing the first day of the second month following the month in which the operator is notified by the Minister of the results of the recalculation until the requisition of a cheque.

Type of Royalty Compensation	Interest OSRR09 Section	EOPS Filed	Report Due Date	Due Date Payment or Refund	Interest Calculated	Interest Rate	Effective Date of Interest Calculation
Overpayment (provisional royalty compensation recalculation)	s.45(6)(c)	N/A	N/A	By the end of the month following the month in which the operator is notified of the recalculation results.	Simple Daily Interest	Prime+1%	Commencing the first day of the second month following the month in which the operator is notified by the Minister of the results of the recalculation until the requisition of a cheque. Pursuant to s.43(5), the Crown is not liable for interest on any amounts of provisional royalty compensation that are reduced under s.43(4)(b) unless the Crown is late in paying the refund amount, but will refund any interest received by it under s.45(1)(a) in respect of those amounts to the extent those amounts are so reduced.

Appendix J

Business Rule Papers and Examples

This Appendix includes 5 papers, which set out a number of business rules respecting cost allocation and cost of service calculations.

The first paper, “Cost Allocation Business Rules” prescribes and illustrates the cost allocation rules for some eleven assets and engineering systems.

The second paper, “Business Rules – Indirect Cost Allocation Ratios for Oil Sands Projects” indicates how the “head count ratio”, “geographic location”, and capital cost ratio” allocation methodologies described in section 8(8) of the OSAC regulation are to be applied.

The third paper, “Allocation of Cogeneration and Steam Generation Costs” set out the business rules for allocating these costs within an integrated oil sands project. Sample calculations for two typical installations are included. A PowerPoint presentation providing more information on this matter is also included.

The fourth paper, “Heat Transfer: Business Rules and Sample Calculation” provides the business rules for calculations of the value of useful heat transferred between the royalty and non-royalty parts of integrated oil sands projects. It also details the calculation of the Site Wide Thermal Energy Value (SWTEV). Materiality issues are discussed and sample calculations provided.

The fifth paper illustrates how the “Cost of Service” is to be calculated where one is required.

Government of Alberta – Alberta Energy

Cost Allocation Business Rules

Oil Sands Operations

1. Partially-Includable assets and engineering systems

Partially-includable assets and engineering systems are those identified in section 14 of the *Oil Sands Royalty Regulation, 2009* (OSRR09) which the Minister may partly include in an oil sands royalty (OSR) Project description. Assets and engineering systems not specifically identified as partially-includable cannot be partly included in a Project. They may be included in their entirety if they meet the project use threshold. If they do not meet the threshold, they cannot be included in the Project.

If the Minister includes (e.g.) 65% of a partially-includable asset or engineering system in a Project, then 65% of the capital and operating costs of that asset or system are eligible to be allowed costs of that Project. Once the proportion of the asset or engineering system included in the Project is established, it will generally remain fixed, unless significant changes to the Project occur and warrant its amendment.

Where these assets or engineering systems relate to an integrated project, the percentage of the asset or engineering system allocated to the integrated shared operations (ISO) of that integrated project must also be specified. That proportion of the costs of the asset or engineering system will be attributed to the ISO. They will subsequently be allocated to the OSR Project, along with all other costs attributed to the ISO, on the basis of Schedule 3 in the *Oil Sands Allowed Cost (Ministerial) Regulation* (OSAC) – i.e. on the basis of the value of energy used by the OSR Project as a percentage of the value of energy used by the integrated project as a whole.

Project operators need to inform Alberta Energy (the Department) if changes are made that would require an amendment to the proportion of the asset or engineering system included in the OSR Project. The Department may also review, from time to time on its own initiative, the proportion of an asset or engineering system included in an OSR Project.

The following business rules establish how the proportion of an asset or engineering system to be included in an OSR Project will be established.

1.1 Control Systems Cost Allocation

Issue

The Control System provides an essential service to integrated oil sands operations and may serve both royalty and non-Royalty Project uses. An appropriate allocation of Control System costs is required for royalty purposes.

Background and Definition

The primary function of the Control System is to allow for monitoring and operation of process units and plant equipment. The Control System is typically composed of the following major components:

1. Control Room Equipment (panels, cabinets, operator interface)
2. Field Instruments (FI)
3. Junction Boxes (JB)
4. Multiplex (MUX)
5. Cables and Cable Trays
6. Control Room Building.

The Control System provides operators remote access to monitor and operate process units and plant equipment on an ongoing basis. The configuration of a typical Control System is shown in Figure 1. The Royalty Project ring fence is indicated by the dashed green line.

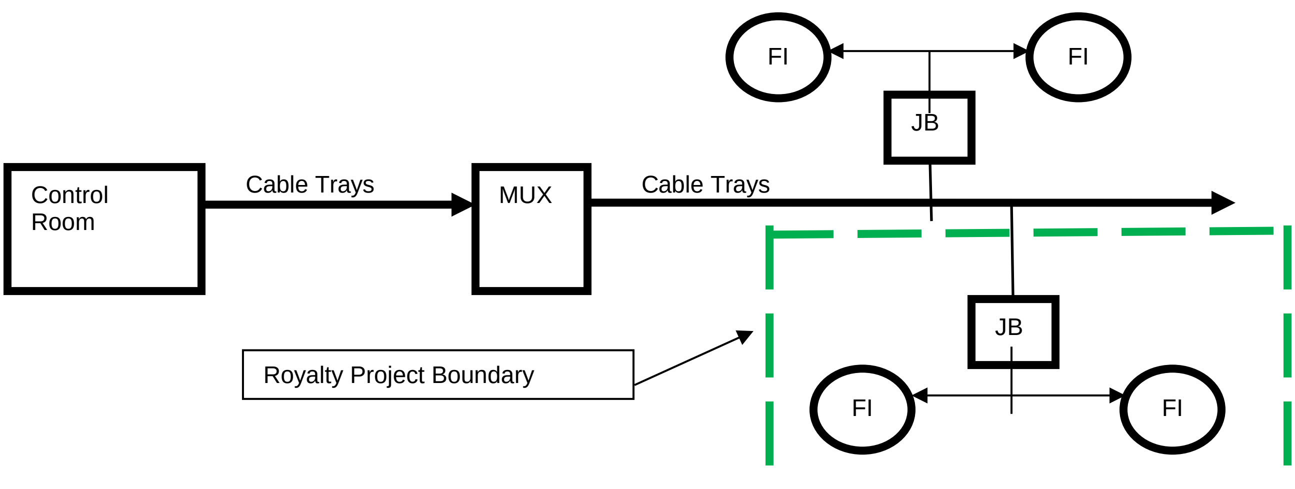


Figure 1 – A Typical Control System

Allocation Methodology

Control systems are partially includable assets under the OSRR09. The proportion of the control system that may be included in the OSR Project will be determined by the proportion of control system costs allocated to the OSR Project by the cost allocation methodology described below. By schedule 2 of the OSAC Regulation, control system costs are to be allocated according to design intent.

As a control system is an operating mechanism, its costs will be largely dependent upon the number of inputs/outputs (I/O). The cost allocation will be based on the relative counts of inputs/outputs that provide service to the Royalty, non-Royalty Project and ISO components.

The costs of the control room equipment, multiplexes and cable trays comprising the Control System will be allocated based on the inputs/outputs count as described below.

$$RPCAF_{CS} = \frac{I/O_{RP}}{(I/O_{RP} + I/O_{NRP} + I/O_{ISO})}$$

Where
$RPCAF_{CS}$= Royalty Project Cost Allocation Factor for Control System
I/O_{RP} = Number of Inputs/Outputs serving OSR Project
I/O_{NRP} = Number of Inputs/Outputs serving non-royalty project
I/O_{ISO} = Number of Inputs/Outputs serving ISO

Implementation

To implement the cost allocation rules for Control Systems the Department will require the following information:

1. Process Flow Diagrams (PFD)
2. Process and Instrumentation Diagrams (P&ID)
3. List of input/outputs (I/O) with corresponding process units or plant equipment (I/O List clearly indicating which units are served by each I/O point).

This information must be provided to the Department when an application is submitted for an expansion, or new OSR Project, where an integrated facility requires Control System cost allocation.

For existing Projects, where an allocation is to be made but no recent capital costs are available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Control System and the allocation of its costs within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator.

Once a cost allocation system is established, it will be subject to audit by the Department, at any time, to ensure the resulting allocations remain appropriate.

1.2 Cooling Water System Cost Allocation

Issue

The Cooling Water System provides an essential service to integrated oil sands operations and may serve both Royalty and non-Royalty Project uses. An appropriate allocation of Cooling Water System costs is required for royalty purposes.

Background and Definition

The primary function of the Cooling Water System is to provide heat rejection to the atmosphere for production and processing facilities in integrated oil sands operations. The Cooling Water System is composed of the following major components:

1. Cooling Towers
2. Pumps – circulation pumps and sump pumps
3. Flow Lines
4. Valves
5. Filters
6. Chemical Treatment – chlorinators and corrosion inhibitors

Allocation Methodology

The Cooling Water System is a partially includable asset under the OSRR09. The sizing and specifications of the Cooling Water System are based on the cooling water requirements of both royalty and non-royalty Project operations. As it will not be feasible to measure actual usage of cooling water, the costs of the Cooling Water System will be allocated based on cooling water demand or utility balance. By schedule 2 of the OSAC Regulation, Cooling Water System Costs are to be allocated according to design intent.

As cooling water demand is predominantly for the upgrader (non-royalty project); all costs of the Cooling Water System could be allocated to the upgrader. However, if the operator provides data to substantiate cooling water demand by the OSR Project, a portion of the Cooling Water System may be included in the OSR Project. The proportion of the cooling water system that may be included in the OSR Project will be determined by the proportion of Cooling Water System costs allocated to the OSR Project by the cost allocation methodology described below.

The costs of the cooling towers, pumps, filters, and chemical treatment systems comprising the Cooling Water System will be allocated based on the design cooling water demand as described below.

Royalty Project Cost Allocation Factor – Cooling Water System	$RPCAF_{CWS}$	Royalty Project cost allocation factor for Cooling Water System
Cooling Water Demand – Royalty Project	CWD_{RP}	Design cooling water demand for Royalty Project components
Cooling Water Demand – Non-Royalty Project	CWD_{NRP}	Design cooling water demand for non-Royalty Project components
Cooling Water Demand – Integrated Shared Operations (ISO)	CWD_{ISO}	Design cooling water demand for ISO
Total Cost – Cooling Water System	TC_{CWS}	Total cost of the Cooling Water System
Royalty Project Allowed Cost – Cooling Water System	$RPAC_{CWS}$	Annual allowed cost of Cooling Water System for the Royalty Project

The proportion of the costs allocated to the royalty Project is given by

$$RPCAF_{CWS} = \frac{CWD_{RP}}{(CWD_{RP} + CWD_{NRP} + CWD_{ISO})}$$

In each year, that proportion of the capital and operating costs of the cooling water system will be an allowed cost of the royalty Project, i.e.:

$RPAC_{CWS} = RPCAF_{CWS}$ x annual operating and capital costs of CWS

Implementation

To implement the cost allocation rules for Cooling Water Systems the Department will require the following information:

1. Process Flow Diagrams (PFD)
2. Process and Instrumentation Diagrams (P&ID)
3. List of design cooling water demand (or utility balance) for production and process facilities

This information must be provided to the Department when an application is submitted for an expansion, or new royalty Project, where an integrated facility requires Cooling Water System cost allocation. No royalty Project approval will be issued without the required information.

For existing OSR Projects where an allocation is to be made but no recent capital costs are available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Cooling Water System and the allocation of its costs within a reasonable time after the Department has made such a request. Department will review the proposal and inform the operator of any required corrections or changes.

Once a cost allocation system is established, it will be subject to audit by the Department, at any time, to ensure the resulting allocations remain appropriate.

1.3 Emergency Power System Cost Allocation

Issue

The Emergency Power System provides an essential service to integrated oil sands operations and may serve both royalty and non-royalty Project uses. An appropriate allocation of Emergency Power System costs is required for royalty purposes.

Background and Definition

The primary function of the Emergency Power System is to provide back-up power for plant equipment and facilities during a power outage. The Emergency Power System is typically composed of the following major components:

1. Generators
2. Transformers
3. Transfer switches
4. Controls

Allocation Methodology

The Emergency Power System is a partially includable asset under the OSRR09. The proportion of the Emergency Power System that may be included in the OSR Project will be determined by the proportion of Emergency Power System costs allocated to the OSR Project by the cost allocation methodology described below. By schedule 2 of the OSAC Regulation, Emergency Power System costs are to be allocated according to design intent.

The Emergency Power System is purely a back-up or contingent system. The sizing and specifications of the Emergency Power System are largely based on the emergency power requirements of both royalty and non-royalty Project components. As it will not be feasible to measure actual usage, the costs of the Emergency Power System will be allocated based on the design emergency power demand of the OSR Project components as a percentage of total design emergency power demand of the integrated project, including integrated shared operations (ISO).

The cost of the Emergency Power System will be allocated as follows:

Royalty Project Cost Allocation Factor – Emergency Power System	$RPCAF_{EPS}$	Royalty Project cost allocation factor for Emergency Power System
Emergency Power Demand – Royalty Project	EPD_{RP}	Design emergency power demand for Royalty Project components
Emergency Power Demand – Non-Royalty Project	EPD_{NRP}	Design emergency power demand for non-Royalty Project components
Emergency Power Demand – ISO	EPD_{ISO}	Design emergency power demand for ISO
Total Cost – Emergency Power System	TC_{EPS}	Total cost of the Emergency Power System
Royalty Project Allowed Cost – Emergency Power System	$RPAC_{EPS}$	Annual allowed cost of Emergency Power System for the Royalty Project

The proportion of the costs of the Emergency Power System allocated to the royalty Project is given by:

$$RPCAF_{EPS} = \frac{EPD_{RP}}{(EPD_{RP} + EPD_{NRP} + EPD_{ISO})}$$

This proportion of the Emergency Power System may be included in the royalty Project.

In each year, that proportion of the capital and operating costs of the cooling water system will be an allowed cost of the royalty Project, i.e.:

$RPAC_{EPS} = RPCAF_{EPS}$ x annual operating and capital costs of EPS

Implementation

To implement the cost allocation rules for Emergency Power Systems the Department will require the following information:

1. Single Line Diagrams (SLD)
2. Emergency Power Load List
3. Plot Plans
4. Site General Arrangement Drawings

This information must be provided to the Department when an application is submitted for an expansion, or new royalty project, where an integrated facility requires Emergency Power System cost allocation.

For existing OSR Projects where an allocation is to be made but no recent capital costs are available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Emergency Power System and the allocation of its costs within a reasonable time after the Department has made such a request. Department will review the proposal and inform the operator of any required corrections or changes.

Once a cost allocation system is established, it will be subject to audit by the Department, at any time, to ensure the resulting allocations remain appropriate.

1.4 Fire Water System Cost Allocation

Issue

The Fire Water System provides an essential service to integrated oil sands operations and may serve both Royalty and non-Royalty Project uses. An appropriate allocation of Fire Water System costs is required for royalty purposes.

Background and Definition

The primary function of the Fire Water System is to provide protection for plant equipment and facilities during an emergency fire incident. The Fire Water System is composed of the following major components:

1. Water tank
2. Fire hydrants and monitors
3. Water mains and flow lines
4. Water pumps
5. Fire Water Pump Building

The Fire Water System does not include any process unit specific fire suppression (gas, foam or chemical) systems. The Fire Water System acts as a safety mechanism to protect plant equipment and facilities during emergency fire incidents. The configuration of a typical Fire Water System is shown in Figure 1. The Royalty Project ring fence is indicated by the dashed green line.

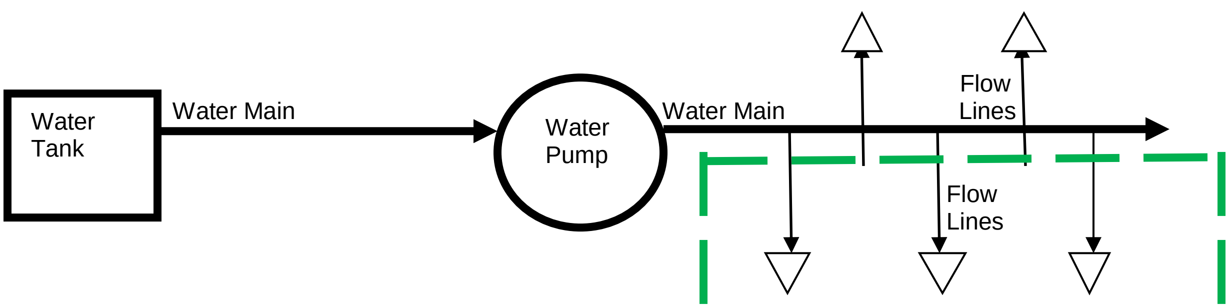


Figure 1 – Fire Water System

Allocation Methodology

The Fire Water System is a partially includable asset under the OSRR09. The proportion of the Fire Water System that may be included in the OSR Project will be determined by the proportion of Fire Water System costs allocated to the OSR Project by the cost allocation methodology described below. By schedule 2 of the OSAC Regulation, Fire Water System costs are to be allocated according to design intent.

The Fire Water System generally serves both royalty and non-royalty Project components. As the Fire Water System is purely an emergency or contingent mechanism, the costs of the Fire Water system are not dependent upon actual usage. The sizing and specifications of the Fire Water System are largely based on the water requirements of both royalty and non-royalty Project components. The capacity of fire hydrants and fire monitors provides a good proxy for the relative fire water requirements of the OSR Project and non-royalty Project components.

The cost allocation of the Fire Water System will be based on the following principles:

a) The cost of flow lines, fire hydrants and monitors inside the Royalty Project Geographic Boundary will be allocated to the royalty Project.

b) The cost of flow lines, fire hydrants and monitors outside the Royalty Project Geographic Boundary will not be allocated to the royalty Project.

c) The cost of water mains, pumps and tanks serving royalty Project and non-project facilities will be allocated based on the capacity of the fire hydrants and monitors, as follows:

The proportion of these costs allocated to the royalty Project is given by:

$$FWSAF_{RP} = \frac{[(RP_{FH} \times C_{FH}) + (RP_{M} \times C_{M})]}{[\{(RP_{FH} + NRP_{FH} + ISO_{FH}) \times C_{FH}\} + \{(RP_{M} + NRP_{M} + ISO_{M}) \times C_{M}\}]}$$

Where
$FWSAF_{RP}$ = Cost Allocation Factor for Fire Water System
RP_{FH} = Number of Fire Hydrants serving Royalty Project
RP_{M} = Number of Monitors serving Royalty Project
C_{FH} = Maximum design flow Capacity of Fire Hydrants (m^3/hr)
C_{M} = Maximum design flow Capacity of Monitors (m^3/hr)
NRP_{FH} = Number of Fire Hydrants serving non-Royalty Project
NRP_{M} = Number of Monitors serving non-Royalty Project
ISO_{FH} = Number of Fire Hydrants serving ISO
ISO_{M} = Number of Monitors serving ISO
$RPAC_{FWS}$ = Annual allowed costs of FWS for royalty Project

The sum of the costs allocated to the royalty Project by (a) and (c), divided by the total cost of the Fire Water System, will determine the proportion of the fire water system that may be included in the royalty Project.

In each year, that proportion of the capital and operating costs of the cooling water system will be an allowed cost of the royalty Project, i.e.:

$RPAC_{FWS} = FWSAF_{RP}$ x annual operating and capital costs of FWS

Implementation

To implement the cost allocation business rules for Fire Water Systems, the Department will require the following information:

1. Process Flow Diagrams (PFD)
2. Process and Instrumentation Diagrams (P&ID)
3. List of fire hydrants and monitors with maximum design flow capacities
4. Fire water design aims/philosophy

This information will need to be provided to the Department when an application is submitted for an expansion or new royalty project where an integrated facility that requires Fire Water System cost allocation.

For existing Projects, where an allocation is to be made but no recent capital costs are available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Fire Water System and the allocation of its costs within a reasonable time after the Department has made such a request. Department will review the proposal and inform the operator of any required corrections or changes.

Once a cost allocation system is established, it will be subject to audit by the Department, at any time, to ensure the resulting allocations remain appropriate.

1.5 Pipe Racks Cost Allocation

Issue

Pipe racks are required for integrated oil sands operations and may serve both Royalty and non-Royalty Project operations. An appropriate allocation of Pipe Rack costs is required for royalty purposes.

Background and Definition

In this document, references to “Pipe racks” will include stick built or modularized Pipe racks and piping on sleepers. The term “Pipe rack components” will refer to the individual Pipe rack modules or the stick built sections or those sections of piping on sleepers. Pipe racks will not refer to stand alone or single pipelines. Single lines which are part of a royalty Project, and generally located in a utility corridor, will be defined and included in the Project Description. Non-basic pipelines (product sales lines or diluent import lines) will not be included in the Project Description. In addition, the term “Pipe racks”, does not include “Stub Racks”, which are short sections of Pipe rack inside the battery limits of a processing unit and generally inside the battery limit valves of the unit. Stub Racks will be included or excluded from the Royalty Project depending on the processing units they serve.

Pipe racks provide infrastructure for transportation of substances and communication between process units in an oil sands development and are a major capital expense for a Project. Transported substances may include petroleum products (bitumen, gas oil, diesel, etc.) and utilities (water, steam, syngas, natural gas, etc.) necessary to support oil sands operations. Pipe racks will generally include the following major components:

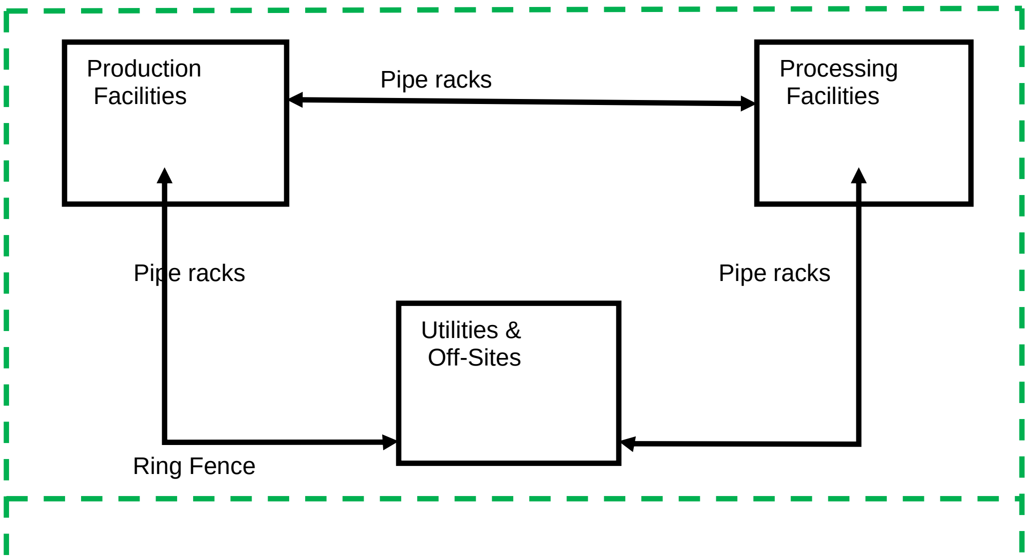
1. Foundations and piles necessary for support.
2. Metal racks required to support pipes.
3. Large pipes used to transport substances.
4. Communication and control wiring in trays.
5. Electrical distribution wiring.

Allocation Methodology

Pipe racks are partially includable assets under the OSRR09. The proportion of the Pipe rack that may be included in the royalty Project will be determined by the proportion of Pipe rack costs allocated to the royalty Project by the cost allocation methodology described below. The allocation methodology is based on the “ratio of length” of the pipe racks located within the royalty Project, as per Schedule 2 of the OSAC Regulation.

If a Pipe rack is owned by the royalty Project owners, located on royalty Project lands, and does not form part of a boundary with other non-royalty project components or areas, the Pipe rack will be included in the Royalty Project and its costs will be eligible to be allowed costs of the Project. This case is shown in Figure 1.

Figure 1 – Simple Royalty Project with all Pipe racks in the Project

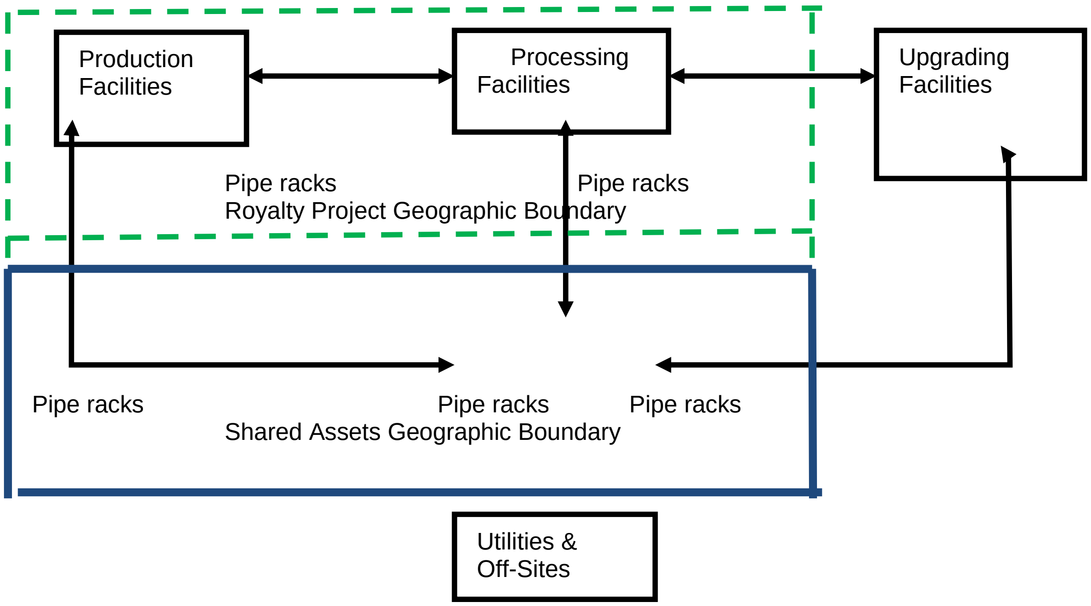


Note: In Figures 1 to 5 the boundary of the royalty Project is indicated with a dashed green line.

For integrated oil sands projects, Pipe rack components may be completely (100%) allocated to a part of the Project (royalty Project, non-royalty Project or Shared Asset) based on the process units that surround them. Pipe rack components on the boundaries between royalty Project, non-royalty project and shared asset areas of the integrated oil sands project, or linking facilities in different areas of the integrated project, will need to be allocated among those areas. An example of this case is shown in Figure 2, where an in-situ or mining royalty Project is integrated with upgrading facilities. The Pipe racks provide services for transportation of substances and communication both within and between the royalty, shared use asset, and non-royalty areas of the project.

These allocations may be accomplished using a simple method, or a complex method or engineering allocation as described below.

Figure 2 – Integrated Project with Pipe racks between multiple components of the development.



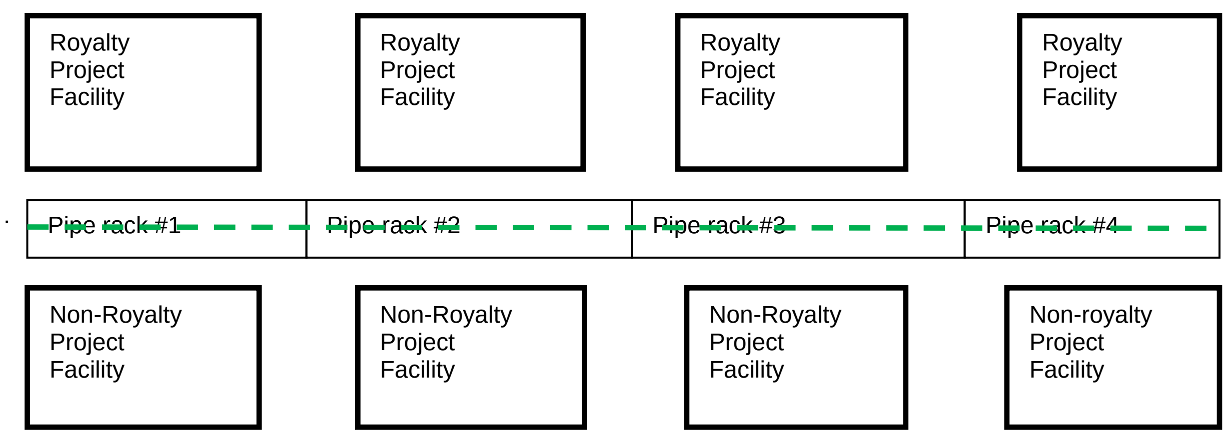
Assumptions:

1. The location of Pipe racks can be accurately identified.
2. Pipe rack costs are discrete and can be linked to specific Pipe rack sections or modules.
3. The Pipe racks may serve Royalty Project, non-Royalty Project, or shared uses.

Cost Allocation Approaches:

1. The "simple method" of Pipe rack cost allocation is based on the relative proximity of the Pipe racks to royalty and non-royalty components of the oil sands project. Pipe rack costs are determined by such factors as material selection, product handling requirements, level of insulation and line density. There is often no simple correlation between Pipe rack costs and individual design parameters. Where Pipe rack section costs can be assumed to be reasonably similar, this approach will allow for an effective allocation without requiring engineering calculations. This will be the default approach to Pipe rack cost allocation and will be used wherever reasonable.

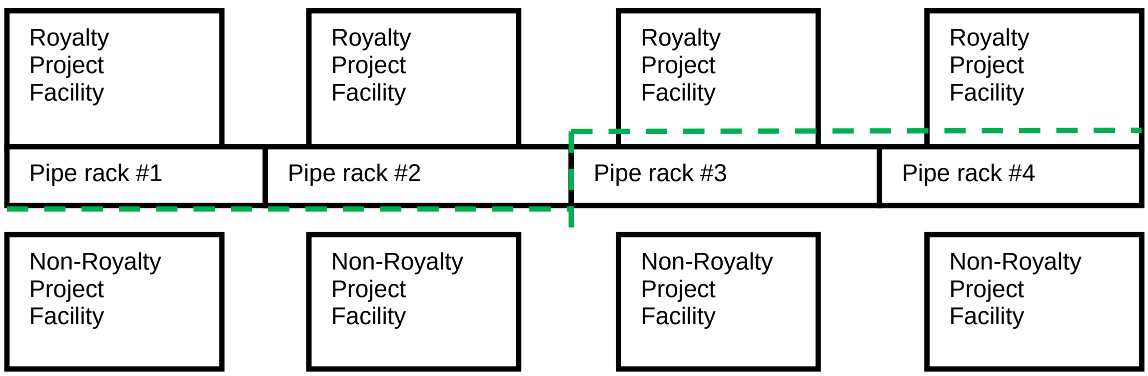
Figure 3 – Simple case where proximity based allocation is sufficient.



In the situation shown in Figure 3, and assuming that the Total Installed Cost (TIC) of Pipe racks #1 to #4 are reasonably similar, we would simply allocate Pipe racks #3 and #4 to the non-Royalty Project and Pipe racks #1 and #2 to the Royalty Project, as shown in Figure 4. One of the criteria for making this assignment is that the resulting ring fence should be continuous and contiguous portions of Pipe racks and Royalty Projects should be grouped together. We will avoid creating "islanded" sections of Pipe rack or Pipe rack separated from other Royalty Project facilities whenever reasonable.

The Geographic Boundaries of the Project, as determined by the Department, will form an attachment to the Project Description of Royalty Projects. This allocation will be an added term and condition of the Project Description for new Royalty Projects.

Figure 4 – Resulting Pipe rack assignment with a simple proximity based allocation.



In the situation where a Royalty Project processing unit or facility is completely or almost completely surrounded by non-Royalty Project components, there will be no allocation of Pipe racks to the Royalty Project. As the use of Pipe racks will be dominated by the non-Royalty Project components, it would not be appropriate to allocate half (½) of each Pipe rack component to the stand alone Royalty Project process unit or facility.

2. <u>In certain complex cases, an engineering allocation may be required for Pipe racks</u>. The Department will, at its discretion, determine the circumstances in which an engineering allocation is required and how it will be carried out. The intent is that this would be done on a very infrequent basis.

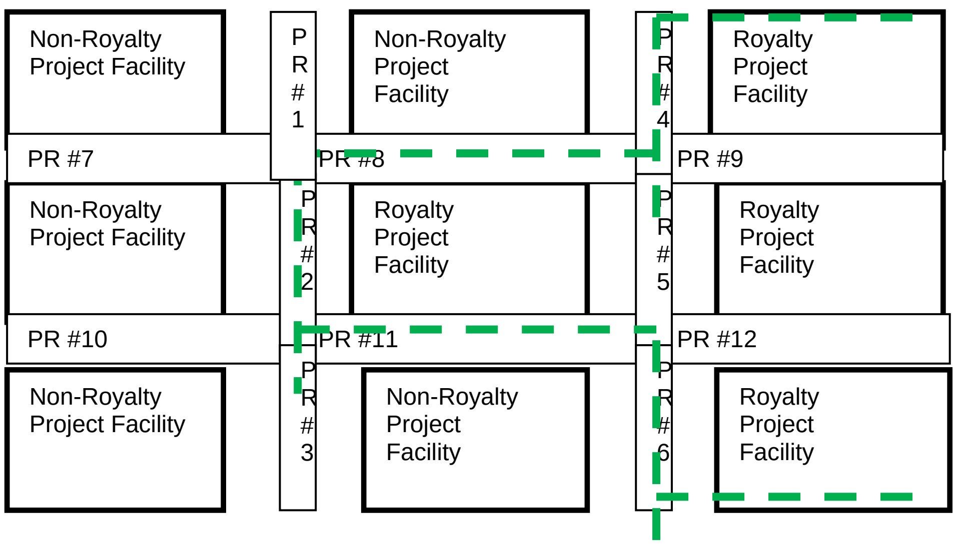
Under this approach as well, the Department may join parts of similar Pipe rack components into one group of assets and assign them to a single use (Project or non-Project) as long as assets of an approximately equivalent value are grouped together and assigned to the opposing use, so that a similar value is transferred out of the project (as in figure 4). This will result in a manageable allocation of Pipe racks and a clear ring fence. The Department will also need to review the allocation and ring fence when necessary (i.e., when there is a major capital expansion) in order to determine whether the allocations are still fair.

Sample Calculations – Pipe rack cost allocation

1. Cost Allocation - Simple Approach:

In Figure 5, assume the Pipe racks #1 to #9 have a capital cost of $2 million each, except Pipe rack #8 which cost $4 million. Pipe racks physically located on the boundary between the Royalty and non-Royalty Project lands or on the boundary between Royalty and non-Royalty Project processing units require allocation. In addition, the Royalty Project processing unit in closest proximity to the Pipe rack in question must be surrounded by five (5) or fewer processing units that are not part of the Royalty Project. Then 50% of the Pipe rack costs may be allocated to the Royalty Project.

Figure 5 – Example Calculation Proximity Based Allocation of costs



Allocation is not required for Pipe racks #1, #3, #7, #10, which form part of the non-Royalty Project facilities, or Pipe racks #5, #9, #12, which form part of the Royalty Project facilities, and whose costs are allowed costs of the Project.

Allocation is required for Pipe racks #2, #4, #6, #8, #11, which are on the boundary between Royalty and non- Royalty Project facilities. For these racks

Royalty Project <u>allocated</u> portion of capital costs = $[0.5 \times (PR_2 + PR_4 + PR_6 + PR_8 + PR_{11})]$
$= [0.5 \times (2 + 4 + 2 + 2 + 2)]$

= $6 million

After the Royalty Project portion of capital costs has been allocated for the Pipe rack components in question (whether modules, sections of stick built Pipe rack, or piping on sleepers) the Department will assign specific Pipe rack units that reflect this calculated cost to the Royalty Project, for the purposes of making a clean and manageable division between Royalty Project and non-Royalty Project assets. The Pipe rack components assigned to the Royalty Project will represent a capital cost approximately equivalent to the portion of capital costs allocated to the Royalty Project. In the situation shown in Figure 5, the capital cost to be allocated to the Royalty Project is $6 million: so Pipe racks #4 and #8 can be allocated to the Royalty Project, and their capital costs will be allowed costs of the Royalty Project.

2. Cost Allocation - Complex Approach

Where the simple geographic approach is not reasonable, the Pipe rack allocation will be determined by the relative use and cost of flow lines. The Pipe rack components must be adjacent to a processing unit or plant that is included in the Royalty Project or a Shared Asset in order to qualify for this type of allocation. Their relative capital costs will depend on the diameter and length of, and materials used in, the process flow lines. If the Pipe rack provides communications or transports substances between functional units both in and out of the Royalty Project, the Pipe rack costs will be allocated to the Royalty Project as follows:

Cost Allocation Factor – Royalty Project	CAF_{RP}	Proportion of capital costs assigned to Royalty Project for Pipe racks.
Royalty Project Process Flow Lines	FL_{RP}	Capital cost of process flow lines between functional units within Royalty Project.
Non-Royalty Project Process Flow Lines	FL_{NRP}	Capital cost of process flow lines between functional units outside of Royalty Project.
Royalty and Non-Royalty Project Flow Lines	$FL_{R\&NRP}$	Capital cost of process flow lines between functional units in and out of the Royalty Project.
Capital Cost	CC_{PR}	Capital cost of Pipe racks.

$$CAF_{RP} = [FL_{RP} + (0.5 \times FL_{R\&NRP})] / (FL_{RP} + FL_{NRP} + FL_{R\&NRP})$$

$$\text{Allowed Capital Costs for Royalty Project} = CAF_{RP} \times CC_{PR}$$

Example Calculation – Complex Approach:

Assume a Pipe rack provides the following services to an integrated oil sands operation:

1. Light gas oil (LGO) flow line between the vacuum distillation unit (NRP) and the hydrotreating unit (NRP) with Capital Costs = $2 million.
2. Bitumen (Bit) flow line between the production battery (RP) and the bitumen extraction facility (RP) with Capital Costs = $1million.
3. Diluted bitumen (Dilbit) flow line between the bitumen extraction facility (RP) and the atmospheric distillation unit (NRP) with Capital Costs = $2 million.

The Allowed Capital Costs for the Pipe racks would be calculated, as follows:

FL_{RP} = $1 million
FL_{NRP} = $2 million
$FL_{R\&NRP}$ = $2 million
CC_{PR} = $10 million

$CAF_{RP} = [1 + (0.5 \times 2)] / (1 + 2 + 2)$
$= 0.40$

Allowed Capital Costs for Royalty Project = 0.40 x $10 million
= $4.0 million

After the Royalty Project allowed capital costs have been determined for the Pipe racks components (whether modules, sections of stick built Pipe rack, or piping on sleepers), the Department will assign specific Pipe rack units to the Royalty Project for the purposes of making a clean and manageable division between Royalty Project and non-Royalty Project assets. The Pipe rack components assigned to the Royalty Project will represent a capital cost approximately equivalent to the total allowed capital cost assigned to the Royalty Project. For example, if there were five (5) identical Pipe rack modules involved in the allocation, and each one had 40% or $4 million dollars assigned to the Royalty Project, the Department could assign two (2) Pipe rack modules (typically those closest to the Royalty Project) to the Royalty Project.

Implementation

To implement the cost allocation rules for Pipe racks, the following documents regarding the oil sands development must be provided to the Department:

1. General Arrangement Drawing of Pipe racks.
2. Plot Plan for the entire site including non-project facilities (Overview and Individual Units).
3. Individual Pipe rack costs.
4. Piping Plans.
5. Cable Tray Layout.
6. Site plan showing location of each Pipe rack or Pipe rack Module.
7. Line Designation Tables for the Pipe racks in question where an Engineering Allocation will be performed.
8. Process and Instrumentation Drawings (P&ID) including any interconnecting P&ID’s for the Pipe racks components in question.
9. Process Flow Diagrams (PFD) for the units near to the Pipe racks.
10. Unit rate prices for modifications to the Pipe racks in new construction.

If the unit rate prices are not available, the Department will have to establish a mechanism to determine the relative costs of the Pipe racks in question. This situation may arise with legacy Projects where historical information is difficult to obtain.

This information will need to be submitted by the operator when an application is submitted for an expansion or new Royalty Project at an integrated facility where Pipe rack cost allocation is required. No Royalty Project approval will be issued without the required information.

For existing projects, where an allocation is required but no recent capital costs are available, the Department will review the information it has on file and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Pipe rack assets, what costs need to be allocated, and the location of flow lines within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator.

Once an allocation system is established, the operator must notify the Department of any substantive changes to the integrated project which may affect the Pipe rack cost allocation methodology. The Department may perform an audit of the allocation methodology on its own initiative at any time, including any aspect of the allocation, to ensure that the allocation methodology remains reasonable.

1.6 Instrument Air System Cost Allocation

Issue

The Instrument Air System provides an essential service to integrated oil sands operations and may serve both royalty and non-Royalty Project uses. An appropriate allocation of Instrument Air System costs is required for royalty purposes.

Background and Definition

The primary function of the Instrument Air System is to supply dry, oil free air to the instrumentation systems of an oil sands operation. An Instrument Air System typically consists of the following major components:

1. Compressor
2. Oil Filter
3. Particulate Filter
4. Air Receiver
5. Air Dryer
6. Local Control Panels

Allocation Methodology

Instrument Air Systems are partially includable assets under the OSRR09. The proportion of the Instrument Air System that may be included in the royalty Project will be determined by the proportion of Instrument Air System costs allocated to the royalty Project by the methodology described below. By schedule 2 of the OSAC Regulation, Instrument Air System costs are to be allocated according to design intent.

a) The costs of compressors, filters, dryers, receivers, and control panels, comprising the Instrument Air System will be allocated based on the design Instrument Air demand as described below.

$$RPCAF_{IAS} = \frac{IAS_{RP}}{(IAS_{RP} + IAS_{NRP} + IAS_{ISO})}$$

Where
$RPCAF_{CS}$= Royalty Project Cost Allocation Factor for Instrument Air System
IAS_{RP} = Number of Instrument Air service points in the royalty Project
IAS_{NRP} = Number of Instrument Air service points in the non-royalty project
IAS_{ISO} = Number of Instrument Air service points in the ISO

The sum of the costs allocated to the royalty Project by (a) and (c), divided by the total costs of the Instrument Air System, will determine the proportion of the Instrument Air System that may be included in the royalty Project.

Implementation

To implement the cost allocation rules for Instrument Air Systems the Department will require the following information:

1. Process Flow Diagrams (PFD)
2. Process and Instrumentation Diagrams (P&ID)
3. List of Instrument Air service points with corresponding process units or plant equipment (clearly indicating which units are served by each Instrument Air service point).

This information must be provided to the Department when an application is submitted for an expansion, or new royalty project, where an integrated facility requires Instrument Air System cost allocation.

For existing projects, where an allocation is to be made but no recent capital costs are available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Instrument Air System and the allocation of its costs within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator.

Once a cost allocation system is established, it will be subject to audit by the Department, at any time, to ensure the resulting allocations remain appropriate.

2. Not partially-includable assets and engineering systems

These assets and engineering systems are not specifically identified in the OSRR09 as being partially includable in a royalty Project. If they meet the Project use threshold of 75% Project use, they can be included in their entirety: in that event all costs associated with them are allowed costs of the Project and other net proceeds (ONP) must be recorded when they provide services to non-Project operations.

Generally these assets and systems, when they form part of an integrated oil sands project, will not meet the royalty Project use threshold and therefore will not be included in the Project description. A cost of service (COS) calculation will be required to value the services they provide to the royalty Project. The rules for calculating the COS are set out in the *Oil Sands Allowed Costs (Ministerial) Regulation* (OSAC).

The following business rules describe how the quantity of services provided by the asset or engineering system to the royalty Project is to be calculated. The quantity of services provided to the Project, multiplied by the COS determined for those services, will represent an allowed cost for the Project.

> In integrated projects with integrated shared operations (ISO), a similar methodology must be applied to calculate the costs of these assets and engineering systems attributable to the ISO. Those costs will subsequently be allocated to the royalty Project, along with all other costs attributed to the ISO, on the basis of Schedule 3 in the OSAC Regulation – i.e. on the basis of the value of energy used by the royalty Project as a percentage of the value of energy used by the integrated project as a whole.

2.1 Boiler Feed Water Treatment Plant Cost Allocation

Issue

The Boiler Feed Water Treatment Plant (or Makeup Water Demineralization Plant) provides an essential service to integrated oil sands operations and may serve both Royalty and non-Royalty Project uses. An appropriate allocation of Boiler Feed Water (BFW) treatment costs is required for royalty purposes.

Background and Definition

The primary function of the Boiler Feed Water Treatment Plant is to remove suspended solids, dissolved gases, salts and minerals from water in order to prevent scale build-up and corrosion in the process equipment. The Boiler Feed Water Treatment Plant provides high quality water for utility boiler blow down, hydrogen plant losses, process equipment losses and other uses in integrated oil sands facilities.

The Boiler Feed Water Treatment Plant does not include equipment or facilities used for supplying, mixing or treating of process water for Steam Assisted Gravity Drainage (SAGD) wells. The Boiler Feed Water Treatment Plant is generally composed of the following major components:

1. Clarification equipment including solids contact clarifiers, solids recirculation clarifiers, pulsed type clarifiers and extended recirculation clarifiers.
2. Filtration equipment including sand filters, dual media filters, gravity filters, pressure filters, precoat filters and ultra filters.
3. Demineralization equipment for electrodialysis, reverse osmosis, and ion exchange processes. Ion exchange demineralization systems may include mixed bed resin demineralizers and condensate polishers.
4. Any other technology used to make demineralised feed water suitable for use in a boiler or high quality cooling water circuit.

The BFW treatment plant may employ the preceding equipment in a number of different combinations depending upon source water characteristics and facility water requirements. In addition, a variety of chemicals are used to clarify, soften, and condition the water.

The uses of high quality boiler feed water may include the following:

(i) Boiler blowdown in the integrated shared operations (ISO).
(ii) Vessel or equipment blowdown in the upgrader.
(iii) Direct use to produce hydrogen in the hydrogen plant.
(iv) Direct use in bitumen production by mixing steam with process fluids.

Allocation Methodology

The BFW treatment plant generally serves both Royalty and non-Royalty Project components, so there will be a need to allocate its costs between the Royalty Project and non-Project uses. The cost of the Boiler Feed Water Treatment Plant will be largely dependent upon the quality and volume of water processed.

The BFW treatment system is designated as a "measured use" engineering system in Schedule 2 of the OSAC Regulation. The BFW treatment costs allocated to the royalty Project will be determined by the measured use of BFW in the royalty Project, multiplied by the COS "unit charge" for BFW.

Water Usage – Royalty Project	WU_{RP}	Annual metered water usage of Royalty Project components.
Water Usage – Non-Royalty Project	WU_{NRP}	Annual metered water usage of non-Royalty Project components
Water Usage – ISO	WU_{ISO}	Annual metered water usage of ISO.
Capital Unit Charge–BFW treatment plant	CC_{BFWTP}	(Annual value of the COS calculation capital cost component for the BFW treatment plant) $\div (WU_{RP} + WU_{NRP} + WU_{ISO})$

Operating Unit Charge –BFW treatment plant	OC_{BFWTP}	(Annual value of the COS calculation operating cost component for the BFW treatment plant) ÷ (WU_{RP} + WU_{NRP} + WU_{ISO})
Allowed Cost BFW Treatment Plant – Royalty Project	$AC_{BFWTP-RP}$	Annual allowed cost of Boiler Feed Water Treatment Plant for the Royalty Project.

$AC_{BFWTP-RP} = WU_{RP} \text{ x } (CC_{BFWTP} + OC_{BFWTP})$

This allocation methodology has been developed for an existing facility with appropriate flow meters to measure water usage. In the case of a new facility, annual design water demand for specific process equipment could be used in the calculation initially. The initial cost allocation could be based on data from utility balances, but would have to be replaced by actual use data as it became available.

Example Calculation
Assuming a BFW treatment plant with the following characteristics:

WU_{RP} = 2 million m^3
WU_{NRP} = 4 million m^3
WU_{SA} = 4 million m^3
CC_{BFWTP} = \$5 million/ (2+4+4) million m^3 = \$0.50 m^3
OC_{BFWTP} = \$1 million/ (2+4+4) million m^3 = \$0.10 m^3

$AC_{BFWTP-RP}$ = 2 million m^3 x (\$0.50 + \$0.10) m3= \$1.2 million

Implementation

To implement the cost allocation rules for the BFW treatment system the Department will require the following information:

1. Process Flow Diagrams (PFD)
2. Utility Balance
3. Process and Instrumentation Diagrams (P&ID)
4. Listing of process equipment with annual water usage or design annual water demand.
5. Actual water usage for the boiler block with separate Royalty Project and non-Royalty Project consumption.

This information must be provided to the Department when an application is submitted for an expansion, or new royalty project, where an integrated facility requires BFW treatment plant cost allocation. A royalty project approval will not be delayed until the actual cost allocation is complete, but the information must be supplied in order to obtain the approval.

For existing projects, where an allocation is to be made but no recent capital cost data is available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the BFW treatment plant and the allocation of its costs within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator. Penalties under the *Oil Sands Royalty Regulation, 2009* may be imposed, or the royalty Project allowed cost allocation deemed to be zero, if the requested information is not supplied.

Once a cost allocation system is established, the operator must inform the Department of any material changes to the integrated project which may affect the allocation methodology. Department may perform an audit of the allocations at any time on its own initiative, to ensure the allocation results are acceptable.

2.2 Flare System Cost Allocation

Issue

The Flare System provides an essential service to integrated oil sands operations and may serve both royalty and non-royalty Project uses. An appropriate allocation of Flare System costs is required for royalty purposes.

Background and Definition

The primary function of the Flare System (or relief system) is to burn gases released by pressure relief valves during unplanned over-pressurization of plant equipment or facilities. The Flare System consists of the following major components:

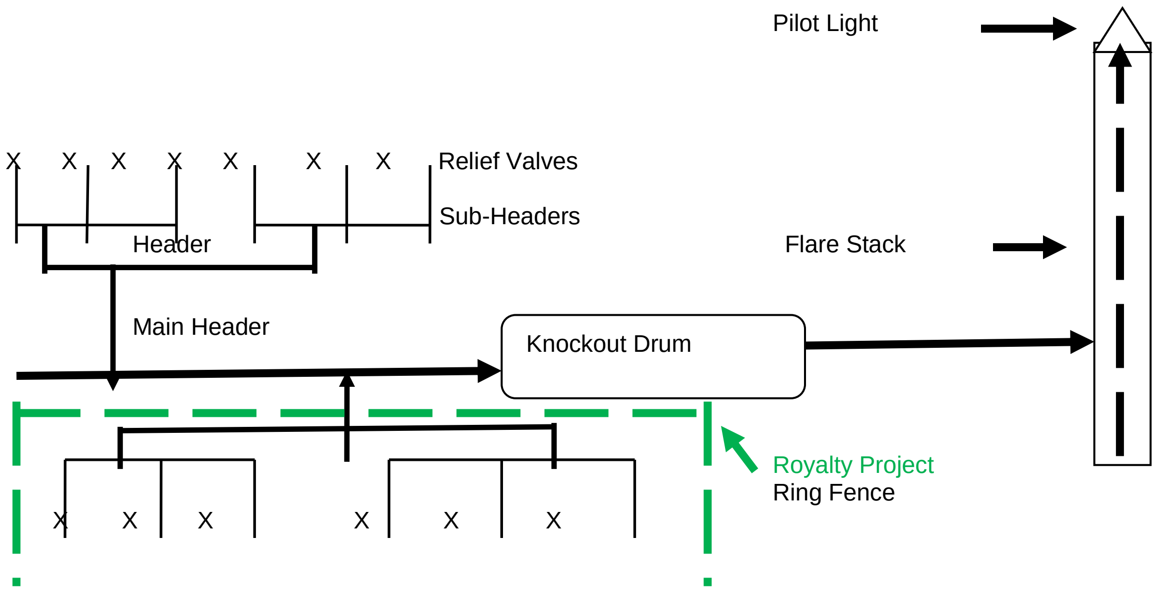
1. Flare System Components
   a) Main flare header
   b) Knockout drum
   c) Flare stack
   d) Pilot light
   e) Relief valves – Typically a spring loaded pressure relief valve actuated by the static pressure upstream of the valve. The valve opens normally in proportion to the pressure increase over the opening pressure.
   f) Relief lines
   g) Sub-headers
   h) Headers

All of which are typically outside the royalty Project, and form part of the non-royalty project facilities or part of the shared assets.

2. Project Relief System Components
   a) Relief Valves
   b) Relief Lines
   c) Sub-headers
   d) Headers

All of which are typically inside the royalty Project ring fence and included in the Project Description as part of the royalty Project.

The Flare System acts as a safety device to protect vessels and pipes from over-pressurization due to unplanned plant upsets. If plant equipment or facilities are over-pressurized, the pressure relief valves automatically release gases and liquids which are routed through flare headers (large piping runs) to the flare stack. The released liquids are removed at the knockout drum and the gases are burned as they exit the flare stack. A small amount of gas is continuously burned (pilot light) in order to sustain complete combustion of any gases released through the flare system. The configuration of a typical Flare System is shown below:



Allocation Methodology

In the situation where there are two Flare Systems, one serving royalty Project uses and one serving non-royalty project uses, the allocation will be based on the principles set out below and will generally result in one system being included in the royalty Project and one system being outside of the royalty Project.

a) If the Flare System is dedicated to the royalty Project and is included in the royalty Project description, its operating and capital costs are allowed costs of the royalty Project. In this situation the Flare System is used exclusively by the Royalty Project, and no cost allocation is required.

b) If the Flare System is not a part of the royalty Project and is dedicated to non-royalty Project use, the costs will not be allowed for royalty purposes.

If the Flare System serves both royalty and the non-royalty Project components, cost allocation will be required. As the Flare System is purely an emergency or contingent mechanism, cost will not be dependent upon actual usage.

The sizing and specifications of the Flare System are largely based on the upset requirements of the upgrader process units. Therefore, the costs of the Flare System (as defined in (1) above) should be fully allocated to the upgrader portion of the project. Project Relief System Components (as defined in (2) above) would be included in the royalty Project, and the costs of those components would be allowed costs of the Project. Project Relief System Components would only include those headers dedicated to the operation of the royalty Project, and would not include the main flare header if it serves non-royalty project uses.

Implementation

To implement the cost allocation rules for flare systems the Department will require the Process Flow Diagrams (PFD) and Process and Instrumentation Diagrams (P&ID) for the oil sands development. This information will need to be provided to the Department when an application is submitted for an expansion or a new royalty Project where an integrated facility requires Flare System cost allocation.

For existing projects, where an allocation required but no recent capital costs are available, the Department will review the information in its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Flare System and the allocation of its costs within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator.

Once a cost allocation system is established, the operator must inform the Department of any material changes to the integrated project which may affect the allocation methodology. Department may perform an audit of the allocations at any time on its own initiative, to ensure the allocation results are acceptable.

2.3 Fuel Gas System Cost Allocation

Issue

The Fuel Gas System provides an essential service to integrated oil sands operations and may serve both royalty and non-royalty Project uses. An appropriate allocation of Fuel Gas System costs is required for royalty purposes.

Background and Definition

The primary function of the Fuel Gas System is to provide natural gas and fuel gas for boilers, fired heaters and hydrogen plants in integrated oil sands operations. The Fuel Gas System typically consists of the following major components:

1. Flow Lines
2. Valves
3. Odorizer
4. Knockout Drum
5. Mixing Drum
6. Pressure Reducer

Allocation Methodology

The Fuel Gas System generally serves both royalty and non-royalty Project components so there will be a need for cost allocation. The cost of the Fuel Gas System will be largely dependent upon the quantity (GJ) of natural/fuel gas distributed.

The cost allocation of the Fuel Gas System will incorporate the following principles:

a) As market based valuation is provided for natural gas used in the royalty Project, the costs for transportation, compression and treatment of natural gas will not be allowed costs for royalty determination purposes.

b) The delivery point for receipt of natural gas will be deemed to be the inlet to the mixing drum located in the Fuel Gas System. In the absence of a mixing drum located in the Fuel Gas system, the delivery point for receipt of natural gas will be the ring fence for the royalty Project.

If the usage by the royalty Project of the natural/fuel gas system is 75% or greater, the fuel gas system could be included in the project description, and its operating and capital costs would be allowed costs of the royalty Project. No cost allocation would be necessary; however, ONP would be recognized for any non-Project use of the system.

If natural/fuel gas system usage by the royalty Project components of an integrated oil sands operation is less than 75% of the total natural/fuel gas system usage, the system will not be included in the Project description. A cost of service (COS) calculation will be required to value the services provided by the system, and its costs will have to be allocated among the royalty Project, shared assets, and non-royalty project.

The Fuel Gas System is designated as a “measured use” engineering system in Schedule 2 of the OSAC. Therefore, the Fuel Gas System costs allocated to the royalty Project will be determined by the measured volume of fuel gas delivered to the royalty Project multiplied by the COS “unit charge” for the Fuel Gas System. Measurement of natural/fuel gas usage by different process units will be required in order to accurately allocate the costs of the Fuel Gas System.

Fuel Gas Usage – Royalty Project	FGU_{RP}	Annual metered natural/fuel gas usage of Royalty Project components
Fuel Gas Usage – Non-Royalty Project	FGU_{NRP}	Annual metered natural/fuel gas usage of Non-Royalty Project components
Fuel Gas Usage – Integrated Shared Operations (ISO)	FGU_{ISO}	Annual metered natural/fuel gas usage of ISO.

Capital Unit Charge – Fuel Gas System	CC_{FGS}	(Annual COS capital cost for the Fuel Gas System) ÷ (FGU_{RP} + FGU_{NRP} + FGU_{ISO})
Operating Unit Charge – Fuel Gas System	OC_{FGS}	(Annual COS operating cost for the Fuel Gas System) ÷ (FGU_{RP} + FGU_{NRP} + FGU_{ISO})
Royalty Project Allowed Cost – Fuel Gas System	$RPAC_{FGS}$	Annual allowed cost of Fuel Gas System for the Royalty Project

$RPAC_{FGS} = (CC_{FGS} + OC_{FGS}) \times FGU_{RP}$

The preceding allocation methodology has been developed for an existing facility with appropriate meters for measurement of natural/fuel gas usage. In the case of a new facility, annual design natural/fuel gas demand for specific process equipment could be used for initial calculations. The initial cost allocation could be based on data from utility balances but would have to be replaced by actual measured use data.

Example Calculation

Assuming a Fuel Gas System with the following characteristics:

FGU_{RP} = 3 million GJ
FGU_{NRP} = 5 million GJ
FGU_{ISO} = 2 million GJ
CC_{FGS} = \$6 million / (3+2+5) million GJ = \$0.60/GJ
OC_{FGS} = \$1 million / (3+2+5) million GJ = \$0.10/GJ

$RPAC_{FGS}$ = 3 million GJ x (\$0.60 +\$0. 10) = \$2.1 million

Implementation

The implementation of the cost allocation business rules for the Fuel Gas System will require that the following information be provided to the Department:

1. Process Flow Diagrams (PFD)
2. Utility Balance
3. Process and Instrumentation Diagrams (P&ID)
4. Listing of process equipment with annual natural/fuel gas usage or design annual natural/fuel gas demand

This information must be provided to the Department when an application is submitted for an expansion, or new royalty project, where an integrated facility requires Fuel Gas System cost allocation.

For existing projects, where an allocation is to be made but no recent capital cost data is available, the Department will review the information on its files and contact the operator to obtain any additional information required. The operator may submit a proposal for defining the scope of the Fuel Gas System and the allocation of its costs within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator.

Once a cost allocation system is established, the operator must inform the Department of any material changes to the integrated project which may affect the allocation methodology. Department may perform an audit of the allocations at any time on its own initiative, to ensure the allocation results are acceptable.

2.4 Raw Water System Cost Allocation

Issue

The Raw Water System provides an essential service to integrated oil sands operations and may serve both Royalty and non-Royalty Project uses. An appropriate allocation of Raw Water System costs is required for royalty purposes.

Background and Definition

The primary function of the Raw Water System is to provide water for production and processing operations in integrated oil sands operations. The Raw Water System is typically composed of the following major components:

1. Flow Lines
2. Water Intake Structure
3. Pump House Building
4. Pumps
5. Valves
6. Tanks

Allocation Methodology

The Raw Water System generally serves both Royalty and non-Royalty Project components so there will be a need for cost allocation. The cost of the Raw Water System will be largely dependent upon the volume of raw water processed.

The Raw Water System is designated as a “measured use” engineering system in Schedule 2 of the OSAC. Therefore, the proportion of the Raw Water System costs allocated to the royalty Project will be determined by the proportion of the measured volume of raw water delivered to the royalty Project to the total measured volume of raw water delivered to the integrated project, including the upgrader and shared assets. As a result, accurate measurement of raw water usage by the Royalty Project and the non-Royalty Project will be required to accurately allocate the costs of the Raw Water System.

If raw water usage by the Royalty Project components of an integrated oil sands operation is less than 75% of the total raw water usage, the Raw Water System will not be included in the Royalty Project. A cost of service (COS) calculation will be required to value the services provided by the Raw Water System to the Royalty Project, Integrated Shared Operations (ISO)(Boiler House), and non-Royalty Project.

Water Usage – Royalty Project	WU_{RP}	Annual metered raw water usage of Royalty Project components
Water Usage – Non-Royalty Project	WU_{NRP}	Annual metered raw water usage of non-Royalty Project components
Water Usage – ISO	WU_{ISO}	Annual metered raw water usage of ISO
Capital Unit Charge – Raw Water System	CC_{RWS}	(Annual COS capital cost for the Raw Water System) ÷ (WU_{RP} + WU_{NRP} + WU_{ISO})
Operating Unit Charge – Raw Water System	OC_{RWS}	(Annual COS operating cost for the Raw Water System) ÷ (WU_{RP} + WU_{NRP} + WU_{ISO})
Royalty Project Allowed Cost – Raw Water System	$RPAC_{RWS}$	Annual allowed cost of Raw Water System for the Royalty Project.

$RPAC_{RWS} = WU_{RP} \times (CC_{RWS} + OC_{RWS})$

The preceding allocation methodology has been developed for an existing facility with appropriate flow meters for measurement of raw water usage. In the case of a new facility, annual design raw water demand for specific production and process equipment could be used in the initial calculation. The initial cost allocation could be based on data from utility balances but would have to be replaced by actual measured use data once the project was operating.

Example Calculation

Assuming a Raw Water System with the following characteristics:

WU_{RP} = 4 million m^3
WU_{NRP} = 4 million m^3
WU_{ISO}= 2 million m^3
CC_{RWS} = \$8 million / (4+4+2) million m^3 = \$0.80 m^3
OC_{RWS} = \$2 million / (4+4+2) million m^3= \$0.20 m^3

$RPAC_{RWS}$ = 4 million m^3 x (\$0.80 +\$0. 20) = \$4 million

Implementation

The following information must be provided to the Department to implement of the cost allocation rules for the Raw Water System:

1. Process Flow Diagrams (PFD)
2. Utility Balance
3. Process and Instrumentation Diagrams (P&ID)
4. Listing of process equipment with annual raw water usage or design annual raw water demand

This information must be provided to the Department when an application is submitted for an expansion or new royalty project at an integrated facility requiring Raw Water System cost allocation. The Royalty Project approval will not be delayed until the actual cost allocation is completed, but the information must be supplied in order to obtain the Project approval. Any new or updated drawings must be supplied to the Department on request.

The operator may submit a proposal for defining the scope of the Raw Water System, and its costs for the COS calculation, within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator. If the information requested by the Department is not provided, penalties the *Oil Sands Royalty Regulation, 2009* may be imposed or the cost allocation may be established by the Department until the information is supplied.

2.5 Transmission Infrastructure Cost Allocation

Issue

Transmission Infrastructure (TI) provides transmission services to oil sands Projects and may serve both royalty and non-royalty Project uses. In integrated projects where the TI is used by both the upgrader (non-royalty Project) and the royalty Project, an appropriate allocation of TI costs is required for royalty purposes.

Background

Oil sands projects utilize TI for transmission of electricity supplied from both commercial and self-generated sources. TI includes transmission lines and substations required to supply electricity to oil sands projects.

The TI serves four major purposes:

a. Import of electricity from supply sources external to the oil sands project;
b. Export of electricity to serve demand external to the oil sands project;
c. Transmission of electricity within the oil sands project; and
d. Provide reliability, system support functions, standby power, and electricity market access for the oil sands development or generator

TI includes all transmission facilities in Alberta that are part of the interconnected electric system. A transmission facility is defined in Section 1(bbb) of the *Electric Utilities Act*, as follows:

> "transmission facility" means an arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step down transformer operating phase to phase at a nominal high voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less, and includes:

(i) transmission lines energized in excess of 25 000 volts,

(ii) insulating and supporting structures,

(iii) substations, transformers and switchgear,

(iv) operational, telecommunication and control devices,

(v) all property of any kind used for the purpose of, or in connection with,

the operation of the transmission facility, including all equipment in a substation used to transmit electric energy from

(A) the low voltage terminal,

to

(B) electric distribution system lines that exit the substation and are

energized at 25 000 volts or less, and

(vi) connections with electric systems in jurisdictions bordering Alberta, but

does not include a generating unit or an electric distribution system.

TI may include the generator step-up transformer, if that transformer is included in the main substation of the oil sands development.

TI Allocation Scope

Equipment which is dedicated to a royalty or non-royalty Project does not need to be allocated. Only equipment which has shared use is subject to cost allocation.

1. TI subject to cost allocation will generally be considered as an integrated system consisting of the following major components:
    a. Interconnection facilities (switches, breakers, transformers, protection, control and communications equipment) provided by the project operator for interconnection to the Alberta Integrated Electric System (AIES).
    b. A radial transmission line(s) and supporting structures from the interconnection point to the main substation.
    c. Main substation facilities (switches, breakers, transformers, protection, control, and communication equipment) required to step-down power to royalty Project, upgrader, utilities and off-sites as well as step-up power from the power generation part of the co-generation facility.

2. The Royalty Project may include power generation facilities specified in the oil sands Royalty Project approval.

3. The TI may transmit electricity used by both royalty, and non-royalty project operations.

Valuation of Transmission Services Methodology

If the TI is a royalty Project asset (i.e. is owned by the royalty Project owners, is defined as part of the Project, and meets the greater than 75% royalty Project use threshold), its capital and operating costs are allowed costs of the royalty Project. ONP will accrue to the Project if the facilities provide services to non-Project facilities.

If the TI is owned by an arm's length third party, valuation will be based on actual charges incurred by the oil sands project for obtaining the service. The charge for TI may be incurred through a negotiated or regulated tariff applied to the oil sands project.

If the TI is owned by a non-arm's length (NAL) affiliate, valuation of the services provided by the TI will be determined by a COS calculation.

Allocation Methodology

An electricity transmission system is a "measured use" engineering system according to Schedule 2 of the OSAC Regulation. The allowed cost to the royalty Project for transmission services is therefore based on the measured power use of the Project multiplied by the COS "unit charge" for transmission services.

Net Generation Electricity Supply	S_{CG}	Net metered annual power export from on-site co-generation plant or the third party generation asset, in Megawatt-hours (MWh)
Royalty Project Electricity Demand	D_{RP}	Net metered annual power use of the Royalty Project, in MWh
Upgrader Electricity Demand	D_U	Net metered annual power use of the upgrader, in MWh.
Integrated Shared Operations (ISO) Electricity Demand	D_{ISO}	Net metered annual power use of ISO, in MWh.
Capital Unit Charge	CC_{TI}	[(Annual COS capital cost for TI)/(D_{RP}+ D_U + D_{ISO}+ S_{CG})], ($/MWh)
Operating Unit Charge	OC_{TI}	[(Annual COS operating cost for TI)/ (D_{RP}+ D_U + D_{ISO}+ S_{CG})], ($/MWh)

Allowed Cost of TI for royalty Project = D_{RP} x (CC_{TI} + OC_{TI}):

In other words, the proportion of the total costs of the TI allocated to the royalty Project (and similarly for the ISO, and the upgrader) is the proportion of its metered use to the total metered use of the integrated project.

Metered power <u>supply</u> (S_{CG} above) is treated like metered power <u>use</u> in the allocation methodology. For example, if one unit supplied 100 MWh and another consumed 100 MWh, each would be allocated 100/ 100+100 = ½ of TI costs. Both suppliers and users use the TI and are allocated costs.

The status of generation assets within an integrated oil sands project can affect the allocation of the TI costs. Consider the following situations.

Case 1:

Assume the electricity generation part of a co-generation facility in an integrated project is <u>not</u> included in the royalty Project: it can be seen as a "stand alone" supply. Consider the following data for a period:

S_{CG} = 3000 GWh
D_{RP} = 1800 GWh
D_U = 1000 GWh
D_{ISO} = 200 GWh
TCC_{TI} = $10 million (total TI capital costs)
TOC_{TI} = $1 million (total TI operating costs)

Then the share of TI costs allocated to the royalty Project would be:

1800 / (1800 + 1000 + 200 + 3000) = 0.30,

for a total of (0.3 x $11 million) = $3.3 million

Alternatively, multiply the COS unit charge by royalty Project use:

CC_{TI} = $10 million/ (1800 + 1000 + 200 + 3000) = $1666.66/GWh
OC_{TI} = $1 million/ (1800 + 1000 + 200 + 3000) = $166.66/GWh

Allowed TI costs to royalty Project = ($1666.66 +$166.66)/GWh x 1800 GWh = $3.3 million.

Case 1(a):

Again we assume the electricity generation part of the Co-generation facility is not included in the royalty Project. Now we specifically include in the TI the radial transmission line connecting the oil sands project to the AIES. Assume that the TI capital costs and TI operating costs remain the same as they were in Case 1.

In case 1, we modeled what was essentially a closed system: generation (S_{CG}) necessarily equaled the sum of consumption ($D_{RP} + D_U + D_{ISO}$). Once we consider the possibility of imports from, or exports to the AIES, this identity is no longer true. If we designate exports to the AIES by X, and imports by M, the relationship becomes:

$$S_{CG} + M = D_{RP} + D_U + D_{ISO} + X, \text{ or}$$

$$S_{CG} + (M - X) = D_{RP} + D_U + D_{ISO}$$

Supply plus net imports is equal to consumption.

Imports to the oil sands project via the radial interconnection are seen as being of benefit to the consumers of electricity. Conversely, exports to the AIES benefit the generator. The implication is that when we calculate the allocation of TI costs, if the oil sands project is a net importer of electricity, the consuming components will bear more than 50% of the TI costs, because their measured use of the TI infrastructure more than the generator.

Modify Case 1 so that generation is <u>reduced</u> by 200 GWh – i.e. net imports were 200 GWh. Then we would have for the period:

S_{CG} = 2800 GWh
D_{RP} = 1800 GWh
D_U = 1000 GWh
D_{ISO} = 200 GWh
TCC_{TI} = $10 million (total TI capital costs)
TOC_{TI} = $1 million (total TI operating costs)

Now the share of TI costs allocated to the royalty Project would be:

1800 / 2800 + (1800 + 1000 + 200) = 0.3103, or

0.3103 x $11 million = $3.4133 million.

Because consumers use the TI more than the generator, the share of total TI costs allocated to consumers is now:

(1800 + 1000 + 200)/ 2800 + (1800 + 1000 + 200) = 3000/5800 = 0.517

And the share of costs borne by the generator is now:

2800 / 2800 + (1800 + 1000 + 200) = 0.4828
In Case 1, the generator and consumers each were allocated 50% of the TI costs.

Conversely, if an oil sands project is a net exporter of electricity, the generator will bear the larger proportion of the TI costs.

Case 2:

Assume the electricity generation portion of the co-generation plant is included in the royalty Project, resulting in net supply (=S_{RP}) of 3000 GWh – 1800 GWh = 1200 GWh from the Royalty Project and net demand from the non-Royalty Project, the allowed operating cost is calculated as follows:

S_{RP} = 1200 GWh
D_U = 1000 GWh
D_{ISO} = 200 GWh
TCC_{TI} = $10 million
TOC_{TI} = $1 million

Then the share of TI costs allocated to the royalty Project would be:

1200 / (1200 + 1000 + 200) = 0.50,

for a total of (0.5 x $11 million) = $5.5 million

Alternatively, multiply the COS unit charge by royalty Project use:

CC_{TI} = $10 million/ (1200 + 1000 + 200) = $4166.66/GWh
OC_{TI} = $1 million/ (1200 + 1000 + 200) = $416.66/GWh

Allowed TI costs to royalty Project = ($4166.66 +$416.66)/GWh x 1200 GWh = $5.5 million.

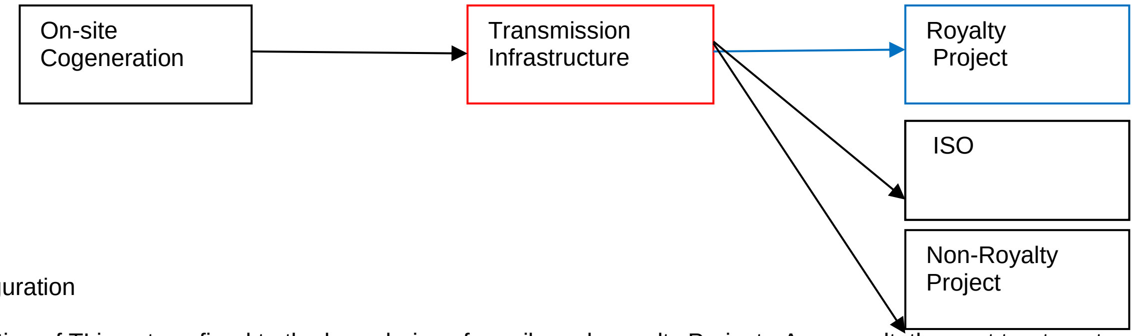
Measuring Use

An upgrader may include electricity generation equipment that is inextricably intertwined with the operation of the upgrader, such as a back pressure steam turbine using excess steam from a process unit. In this case, the net use of the upgrader would be the net demand of the upgrader, considering the combination of generation and use that occurs within it. In most cases, an upgrader would be a net demand or load on the system. The same approach would apply to a royalty Project that includes generation facilities. The net use of a royalty Project will be the net amount of the generation and use within that component of the project.

This approach has been chosen because the Department will generally not have information on the generation and/or use of electricity within each individual asset. However, the net use of a given process unit or operational area at an oil sands development can be determined.

For example, in an oil sands project structured as in Figure 1, the net amount of generation from the co-generation plant should be known. The net amount of use or demand from an upgrader should also be transparent and easily determined.

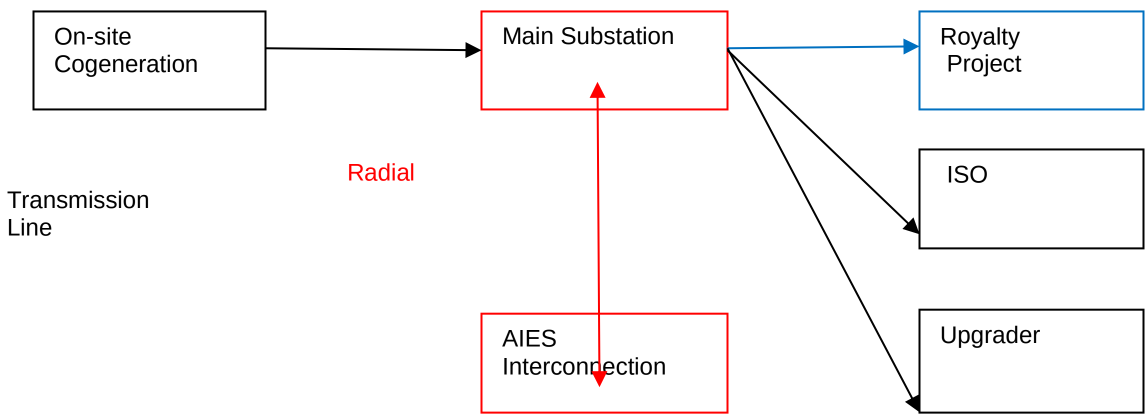
Figure 1 – Electrical Interfaces at an Oil Sands Development



TI Configuration

The location of TI is not confined to the boundaries of an oil sands royalty Project. As a result, the cost treatment of TI will be affected by the location and ownership of transmission facilities. A generic configuration for TI for an oil sands project is presented below in Figure #2.

Figure 2 – A generic integrated oil sands project's Transmission Infrastructure (red), Non-Royalty Project assets (black), and Royalty Project ring fence (blue).



Implementation

To implement the cost allocation business rule for TI the Department will require Single Line Diagrams (SLD), Load Lists, Plot Plans and Site General Arrangement Drawings for the oil sands development. Each service or use component will have to be metered for cost allocation purposes. Information regarding the SLD, Plot Plans and proposed metering locations must be provided to the Department when an application is submitted for an expansion of, or a new royalty Project at, a facility requiring TI cost allocation.

For an existing project, the Department will review the information on its files and contact the operator to obtain any additional information required for the TI allocation. The operator will submit a proposal defining the scope of the TI assets, what costs need to be allocated, and where the required measurements are to be taken within a reasonable time after the Department has made such a request. The Department will review the proposal and communicate any required corrections or changes to the operator.

Once a cost allocation system is established, the Department may audit it at any time, and review any aspect of the allocation it deems necessary to be satisfied that the results are acceptable. An operator must inform the Department of any changes to the integrated project that might substantively affect the allocation methodology.

If in an integrated project there are components of an electric distribution system that serve both royalty and non-royalty project uses and need to be allocated, the allocation method will be the same as for TI.

Government of Alberta – Alberta Energy

Business Rules - Indirect Cost Allocation Ratios for Oil Sands Projects

Business Rules – Indirect Cost Allocation Ratios for Oil Sands Projects

Integrated oil sands projects, when allocating costs between Project and non-Project uses, are required to follow Schedules 2 and 3 of the Oil Sands Allowed Costs (Ministerial) Regulation (“the OSAC”).

Non-integrated oil sands Projects, when allocating costs between Projects or between Project and non-Project uses, are required to follow Schedule 2 of the OSAC.

If a Project operator believes that the allocation methodology specified in Schedule 2 of the OSAC cannot be applied to their Project, or that the type of cost they must allocate is not listed in Schedule 2, they can propose an allocation methodology in respect of that cost to the Minister.

Integrated project operators, when proposing an allocation methodology for such costs, must apply one or more of the following three methodologies:

1. Head count ratios, for facilities and personnel providing “people” services, such as catering, cafeterias, and medical facilities.

2. Capital cost ratios, for site related facilities such as security, fences, site maintenance, and procurement staff.

3. Geographic location, for facilities such as shared parking lots and roads located on project lands.

Operators of non-integrated Projects are not restricted to the use of these three methodologies, but may utilize them if they are relevant to their situation. For example, a head count ratio may be a useful method of allocating “people” service costs between multiple royalty Projects.

In all cases, the final authority to determine cost allocations not specified in Sections 2 or 3 of the OSAC rests with the Minister.

The basic principles for the application of these three methodologies follow.

1. Head Count Ratios

A head count ratio is used as a proxy to determine who is using a given facility without actually measuring the use of the facility. It is used in cases where such actual measurement would be impractical or unduly costly.

In calculating head count ratios, only employees working for the Project operator are considered: contractor employees are not included in the calculation. The head count ratio (“HCR”) is based on the full-time equivalent (FTE) employment assigned by the operator to the royalty Project (“OSR”) and to non-royalty (“non-OSR”) operations.

HCR = OSR FTEs / (OSR FTEs + non-OSR FTEs)

The proportion of the facility’s costs that may be allocated to the royalty Project is determined by the head count ratio.

In deriving the FTEs for the above calculation:

- Employees dedicated 100% to the OSR are OSR FTEs;
- Employees dedicated 100% to the non-OSR are non-OSR FTEs;
- Employees working on both the OSR and non-OSR will have their FTEs split 50/50 between the OSR and non-OSR;
- Again, contractor employees are excluded.

Two types of head count ratio may be used in developing this allocation.

a. Generic Head Count Ratio

This ratio should be sufficient for most allocations on integrated oil sands projects. It will simply be the ratio of the FTEs of employment assigned to the royalty Project to the total FTEs of employment in the integrated project. It will not attempt to assess whether staff from the OSR are more or less likely to use a particular facility than non-OSR staff. It is a simple calculation, and one which is likely to be reasonably accurate given the nature of integrated operations, and the proximity of OSR and non-OSR components.

b. Facility Specific Head Count Ratio

If a facility on an integrated project is so located that users are very likely to come from OSR and non-OSR operations in a ratio significantly different than the generic head count ratio, the Minister may require the use of a facility specific head count ratio that reflects this. For example, in an integrated project, a cafeteria located next to the mine site would likely be used almost exclusively by mining (OSR) staff. In this case, it will be necessary to define the "pool" of potential users of a specific facility – which will be a subset of the total integrated project employees – and calculate the head count ratio based on this pool and not total employment.

The facility specific head count ratio would also be a reasonable basis, in some circumstances, for the allocation of costs between multiple royalty Projects.

2. Capital Cost Ratios

Use of a capital cost ratio would allocate certain costs of an integrated project to the royalty Project based on the ratio:

Capital Cost Ratio = Total OSR Capital Cost / Total Integrated Project Capital Cost

While simple in concept, this approach could be difficult to implement. Would it be based on book value, or original cost? It could also be circular in some circumstances. Given the magnitude of the costs to be allocated by the capital cost ratio, it doesn't seem appropriate to adopt an unduly complex approach.

Therefore, the Department has decided to adopt a default, or **Generic Capital Cost Ratio**, for each integrated project, to deal with the allocation of most costs requiring allocation by a capital cost ratio methodology.

These Generic Capital Cost Ratios will be technology specific.

- For integrated mining / on-site upgrading operations, the generic capital cost ratios will be set at approximately 60% OSR / 40% non-OSR.
- For integrated in situ / upgrading projects with gasification technology, the capital cost ratios will be set at approximately 40% OSR / 60% non-OSR.

The Department may vary these ratios, from time to time, if warranted by new data or substantive amendments to the projects.

Should a new integrated project using a different technology be developed, the Minister will determine an appropriate Generic Capital Cost Ratio for the project.

Two other forms of capital cost ratio may be used for specific allocations.

a. Book Value Capital Cost Ratio

A Book Value Capital Cost Ratio will be used for the allocation of property taxes, as property taxes are based on the assessed book value of assets, plus a small amount for land.

To construct this ratio, it will be necessary to allocate the value of shared assets between the OSR and non-OSR operations. This allocation will be determined by the general cost allocation rules. The generic capital cost ratio may be used to allocate book values that cannot be allocated by these rules.

Project Specific Capital Cost Ratio

For a cost tied to a specific project or phase – such as a Project Management Office or temporary work facilities – that is to be allocated by a capital cost ratio, the Department will base that ratio on the capital spent for that specific project.

3. Geographic Location

To allow for the allocation of those costs that are to be based on geographic location, the Department will develop, for all integrated projects, geographic descriptions of

- the royalty Project,
- integrated shared operations, and
- upgrading operations

that will determine the boundaries between these project components.

Once these boundaries are established, they will be used to allocate the costs of the appropriate systems as follows:

- Assets or systems 100% within the royalty Project will have 100% of their costs allowed.
- Assets or systems outside the royalty Project will not be allowed costs.*
- For assets which cross the geographic boundaries, and are shared and allocable, the percentage of the asset or system inside the royalty Project will determine the percentage of its costs which are allowed costs of the royalty Project.

  *Costs allocated to the integrated shared operations may be partly allocated to the royalty Project according to Schedule 3 f the OSAC.

Government of Alberta – Alberta Energy

Allocation of Cogeneration and Steam Generation Costs

Oil Sands Operations

Issue

Oil sands Projects require significant amounts of steam and electricity for the extraction of bitumen from the reservoir (SAGD) or from mined oil sands ore. Steam and electricity are produced through a variety of generation processes that may include cogeneration units and stand alone steam or power generators. Cogeneration facilities use a fuel source, often natural gas, to produce electricity and co-produce steam simultaneously.

In an integrated project, the steam and electricity produced by these generators is likely used by both the upgrader (non-royalty Project) and the royalty Project. An appropriate allocation of the costs of generating this steam and electricity is required for royalty calculation purposes under the generic oil sands royalty regime.

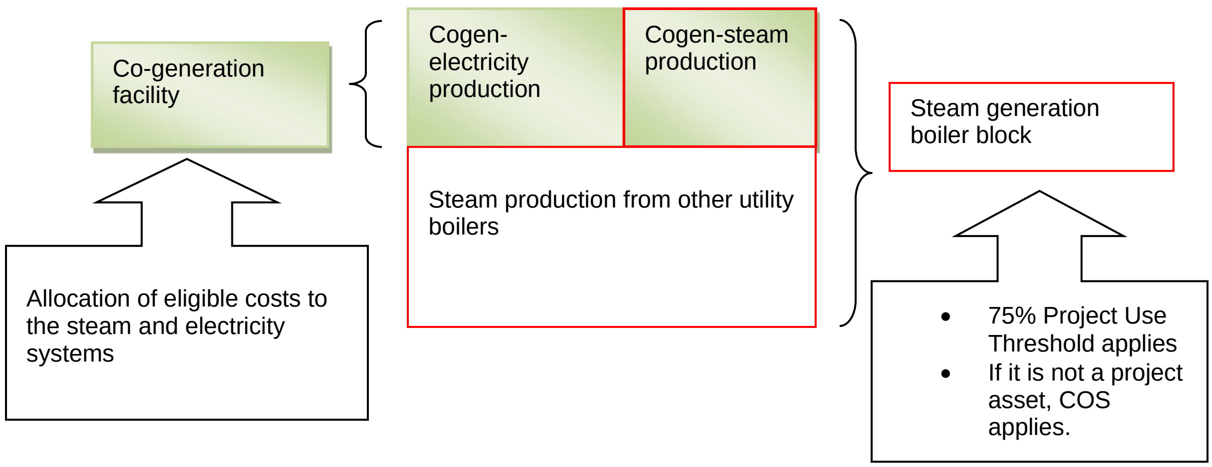
Background and Definitions

The recognition of cogeneration and other steam generation costs for Alberta Energy (the Department) royalty purposes is governed by the *Oil Sands Allowed Cost (Ministerial) Regulation*. Cogeneration and other steam generation are fundamental costs of a royalty Project under section 4(1)(a) of the OSACR and are specifically included costs mentioned in items 3, 4, 18 and 19 in Schedule 1 of that regulation.

Although most steam is usually produced in a dedicated steam generation boiler block in Utility Operations (or Energy Services Operations), some steam is created from process heat in upgrader facilities such as Gasification Plants, Steam Methane Reforming Hydrogen manufacturing plants, and Sulphur Recovery plants. Tracking the sources of comingled steam would be complex though not impossible. This complexity is increased by the fact that multiple qualities of steam (usually at least 3) are produced and distributed through steam headers from producers to consumers. It would be impractical to consider a separate Cost of Service (COS) valuation for each quality of steam and for each source of production (process heat in upgrader, process heat in royalty Project [i.e. Diluent Recovery Unit steam generator]), or the steam generation block). For this reason, the Department has determined that there only be one value for a Gigajoule (GJ) of steam energy in an integrated oil sands project, regardless of where it is generated or consumed. This will be the unit value of a GJ of steam as determined by a COS calculation for the steam generation boiler block. This boiler block may consist of different boilers or a combination of boilers and cogeneration Heat Recovery Steam Generators (HRSGs).

The single value for a GJ of steam will also simplify the determination of royalty Project use of steam. It allows us to simply sum the steam from multiple headers which provide steam to the royalty Project to get the total GJ provided to the royalty Project as a proportion of the total GJ of steam provided by the Boiler (not the total supply of steam provided to the headers). Note: if the amount of steam provided to the royalty Project is greater than the amount produced by the boiler block, a special engineering analysis may have to be conducted by Oil Sands Strategy and Operations to determine if this valuation and allocation methodology is still appropriate. The operator will still submit their royalty Project Costs as if each GJ of steam had the same value, and apply that value to all the steam used by the royalty Project.

In conclusion, determining allowed costs for cogeneration units will require an allocation of eligible costs (including fuel costs, asset costs and ongoing maintenance costs), to the steam and electricity production systems. The steam portion of cogeneration systems is treated as part of the steam generation boiler block. This boiler block may consist of different boilers or a combination of boilers and cogeneration HRSGs. Then the cost of each system (electricity and the steam generation boiler block) can be allocated between its oil sands royalty Project and non-project uses, based on the measured use of each product. The following graphic demonstrates the allocation framework:



Note: The allocation method presented in this paper only applies to steam units and cogen-electricity units that are shared between royalty Project and Non-project uses. Steam and cogen-electricity, which can be conclusively determined to come from a specific source that is dedicated to either royalty Project operations or upgrading operations, are excluded - as there is no need for allocation in these circumstances. Steam use by a steam turbine to generate electricity will be considered a non-royalty Project use of steam, as the electricity generated by the steam will be valued at the Fair Market Value (FMV) of electricity, independent of input costs.

General Allocation and Cost Determination Process

1. Determine the input fuel costs that are attributable to steam production vs. electricity production:
   - The value of input fuel(s) to the Cogeneration system will be determined per the *Oil Sands Allowed Cost (Ministerial) Regulation*, based on the price paid in arm's length transactions or the FMV of the fuel(s) as determined by the Minister.
   - Fuel consumed for process steam generation in the Cogeneration unit will be determined by the fuel charged to steam (FCS) calculation, based on the measured useful energy in the process steam used for heating purposes and assuming 85% thermal efficiency of a boiler or HRSG unit.
   - I.e. FCS (GJ) = (useful energy in process steam / 0.85)
   - Fuel charged to electricity (FCE) = Total fuel consumption in cogeneration unit – FCS.

2. Allocate the costs of assets or engineering systems which serve both the cogeneration units and other units:
   - Assets such as Water Treatment Plants provide services to both the Cogeneration units and other units. The portion of the asset's costs which are attributable to the cogeneration unit will be determined by the portion of services provided by the asset to the cogeneration unit. The costs allocated to the cogeneration unit will then be divided between steam and electricity production.

3. Allocate the dedicated components of the Cogeneration system into electricity only, steam only, and shared categories:
   - The final allocation of these components must be approved by Oil Sands Strategy and Operations Division.
   - Components which function primarily to provide useful heat will be allocated to the steam portion of the Cogeneration system; components which function primarily to provide electricity will be allocated to the electricity portion.
   - Eligible maintenance and repair costs on a component will be considered operating costs of that component.
   - Shared components and their associated costs will be allocated based on the fuel charged to steam /fuel charged to electricity ratio.

4. Determine the cost of steam that is provided to the Royalty Project.

5. Determine the cost of Electricity that is provided to the Royalty Project.

Cost Methodologies:

1. Determining the cost of steam provided to the Royalty Project.

Determining the Level of Royalty Project Use

The net use of steam (in GJ's) by the royalty Project must be calculated to determine the level of royalty Project use of the steam boiler block. The level of royalty Project use will determine whether the steam boiler block meets the Project use threshold of 75% and can therefore be included in the royalty Project. In this case, all the eligible costs of the steam boiler block, including fuel, are allowed costs of the Project. Other net proceeds (ONP) will accrue if the Project provides net steam energy to non-Project operations.

It is likely that, in most integrated projects, the royalty Project use of steam will be less than 75%. Then the steam boiler block will not be included in the royalty Project, and the allowed cost for the steam it supplies to the royalty Project will be: the common value of steam for the integrated project x GJs used by the royalty Project. If the steam boiler block is a Project asset, the amount of ONP attributed to the Project for the net steam energy provided to non-Project operations will be calculated in the same manner.

The calculation of net royalty Project use of steam must consider:

- Any steam generated by the royalty Project which is exported.
- Energy contained in boiler feed water or steam condensate that is exported from the royalty Project.
- Energy returned to the utility boiler as boiler feed water or steam condensate.

For a new royalty Project, or proposed expansion, this level of use calculation may initially be performed using design steam balance information.

The total steam energy production of the utility boiler (in GJs) must also be calculated. The inputs to this calculation must come from final design documents (i.e. Issued for Construction documents) and be stamped by a P. Eng. The calculation itself must also be performed and stamped by a Professional Engineer.

For existing operational royalty Projects the level of use should be calculated using actual operating data. Actual measurements of steam, boiler feed water and condensate flows, including temperatures and pressures, must be used to calculate the net steam energy produced by the steam boiler and the net steam energy provided to the royalty Project. This calculation will have to be performed and stamped by a P. Eng.

Whether this calculation is based on design information or actual operations, the Minister will retain the right to modify the calculation if circumstances require it.

Where:

Level of Use of a Steam Boiler for an existing royalty Project = $LOU_{SB\ RP}$

Net Steam Energy Provided to the royalty Project in GJs = NE_{RP}

Net Steam Energy Produced by the steam boiler in GJs = NE_{SB}

Then:

$LOU_{SB\ RP} = NE_{RP} / NE_{SB}$

Cost of Service Calculation

A Cost of Service (COS) calculation will determine the unit value for a GJ of shared steam on an integrated project. This calculation will be performed on all the primary steam generating assets which produce shared steam (steam boilers and the steam portion of Cogeneration units) individually, and a capacity-weighted average value will be determined for a GJ of steam.

So if the COS unit charge per GJ of steam for a steam unit "i" is $Value_i$, the number of GJ produced by unit "i" is GJ_i, and there are "n" separate units in the boiler block, then:

n

Value of shared steam per GJ = $\sum_{i=1} (Value_i \times GJ_i) / \sum_{i=1} (GJ_i)$

Implementation

The information required for an initial level of use calculation on a new project or an expansion must be provided to the Department when an application is submitted for approval of such a Project.

The Department will review the information on file and contact the operator to obtain additional information required for existing projects where an allocation is to be made but no recent capital costs are available. The operator must submit a proposal defining the scope of the Utility Steam Generation Facility System and the costs needing allocation within a reasonable time after the Department has made such a request. The Department will review the proposal and identify any corrections or changes to the operator. Once a cost allocation system is established, the Department may perform an audit of the allocations at any time within the audit window, with respect to any aspect of the allocation it deems appropriate.

The operator must provide a steam balance for the entire plant and a steam & condensate flow diagram as well as the P & ID (Piping and Instrumentation Diagram) for these systems. These are reference documents for establishing the steam usage in the royalty units. Meter readings recording steam flow in the royalty units must also be provided for legacy units at operating Projects.

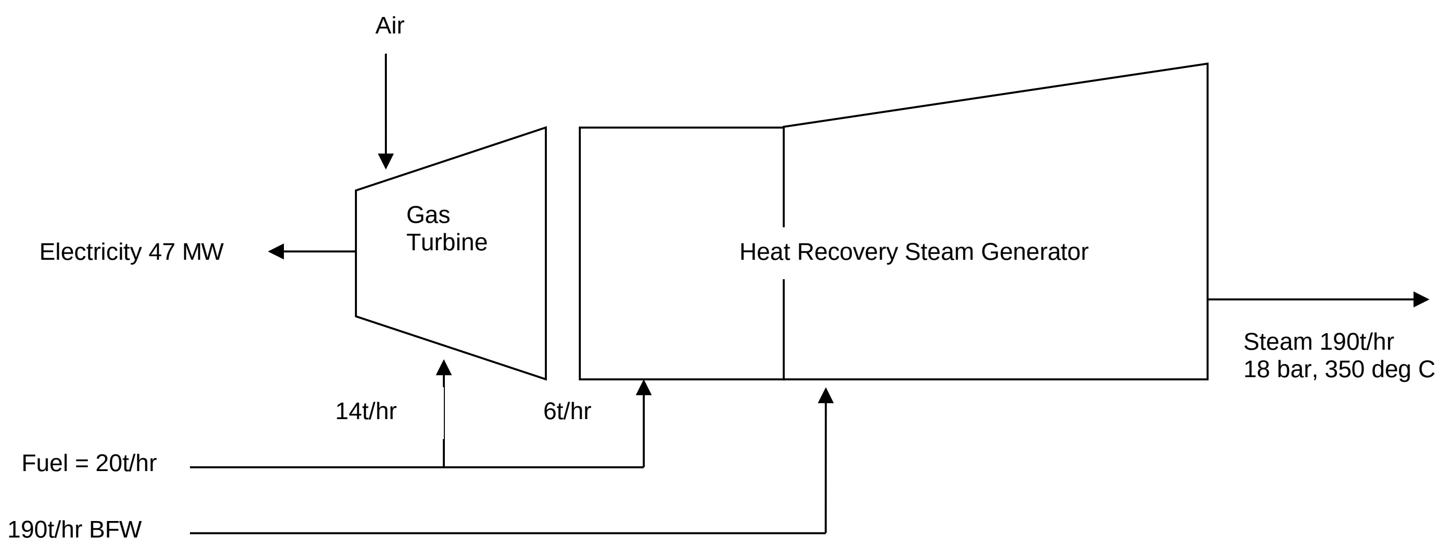
2. Determining the cost of electricity to the Royalty Project.
The FMV of all electricity produced by a cogeneration unit in a month and consumed or sold at non-arm's length will be the average Pool Price reported by the Alberta Electric System Operator (AESO) for that month. Any electricity purchased or sold at arm's length will be valued at that arm's length price.

Because a FMV can be established, there is no need to use a COS approach. Only if a FMV could not be determined would the value of electricity be subject to COS determination.

Typical Cogeneration COS Examples:

Note: Steam Generation systems are one of the measured use systems that uses actual throughput for all the COS calculations

1. COS for a Gas Turbine Generator and Waste Heat Boiler Configuration:
<u>Note:</u> Diagram shows capacity, not throughput



The costs for the system are:

Capital Cost	$150,000 KCAD - Assume 33% for steam portion & 67% for electricity portion
Operating Cost	$700 KCAD - Assume 33% for steam portion & 67% for electricity portion
Sustaining Capital	$10 KCAD - Assume 33% for steam portion & 67% for electricity portion
Maintenance	$2,000 KCAD - Assume 33% for steam portion & 67% for electricity portion
Overhead	$200 KCAD - Assume 33% for steam portion & 67% for electricity portion
Long Term Bond Rate	4% = Return on Capital (ROC)
Depreciation	25 years straight-line

Other information:

Actual throughput	70% of capacity = 133t/hr
Steam Enthalpy	3143 kJ/kg
Energy in BFW	126 kJ/kg
Useful Energy	3143-126 = 3017 kJ/kg
LHV for Natural gas	50 MJ/kg
Price of Natural Gas	$4/GJ = $200.8/tonne
Price of Boiler Feed Water	$3/tonne
Thermal Efficiency	85%

Determine the Level of use (LOU) for the Royalty Project (RP):
Net steam produced = 133 t/hr
Net steam consumed in RP = 99 t/hr

$$LOU_{RP} = \frac{99\ t/hr}{133\ t/hr}$$
$$LOU_{RP} = 74\%$$

Determine the COS calculation:
Determine the Fuel Charged to Steam (FCS) for the year:

$$FCS = \frac{Steam\ (\frac{GJ}{year})}{Thermal\ Efficiency}$$

Where:
Thermal Efficiency = 85%

$$Steam = \frac{\frac{133t}{hr} * \frac{24hr}{d} * \frac{365d}{year} * \frac{1000kg}{t} * \frac{3017kJ}{kg}}{\frac{1000000kJ}{GJ}}$$

$$Steam = 3{,}515{,}046\ GJ/year$$

So:

$$FCS = \frac{3{,}515{,}046\ \ (\frac{GJ}{year})}{85\%}$$

$$FCS = 4{,}135{,}349 \frac{GJ}{year}$$

Convert FCS to t/hr:

$$FCS = \frac{4{,}135{,}349 \frac{GJ}{year} * 1000 \frac{MJ}{GJ}}{50 \frac{MJ}{kg} * 1000 \frac{kg}{t}}$$

$$FCS = 82{,}707\ \ t/year$$
$$FCS = 9.4\ t/hr$$

Determine the fuel charged to electricity (FCE):

$$FCE = total\ fuel - FCS$$
$$FCE = (70\% * 20 \frac{t}{hr}) - 9.4 \frac{t}{hr}$$

$$FCE = 4.6 \frac{t}{hr}$$

Use the FCS to determine fuel costs for steam production:

$$Fuel\ cost_{steam} = \frac{82{,}707 * 200.8 \frac{\$}{t}}{70\% * 190 \frac{t}{hr} * 24 \frac{hr}{d} * 365 \frac{d}{year}}$$
$$Fuel\ cost_{steam} = \$14.3/tonne$$

Determine the capital unit charge (CU):

$$CU = \frac{ROC + Depreciation}{actual\ throughput}$$
$$CU = \frac{4\% * \frac{49{,}500{,}000 + 47{,}520{,}000}{2} + 4\% * 49{,}500{,}000}{70\% *\ 190\ t/hr * 24 \frac{hr}{d} * 365 \frac{d}{year}}$$
$$CU = \$3.4/tonne$$

Determine the operating unit charge (OU):

$$OU = \frac{total\ opex\ cost}{actual\ throughput}$$

$$OU = \frac{(\$700{,}000 + \$2{,}000{,}000 + \$10{,}000 + \$200{,}000) * 33\%}{70\% * 190\frac{t}{hr} * 24\frac{hr}{day} * 365\frac{d}{year}}$$

$$OU = \$0.82/tonne$$

Determine total COS:

$$COS = Fuel\ cost_{steam} + BFW\ cost + CU + OU$$

$$COS = \frac{\$14.3}{tonne} + \frac{\$3}{tonne} + \frac{\$3.4}{tonne} + \frac{\$0.82}{tonne}$$

$$COS = \frac{\$21.50}{tonne}$$

Convert to a GJ basis:

$$COS = \frac{\$21.5/tonne}{3017\frac{kJ}{kg} * 1000\frac{kg}{tonne}} * 1000000kJ/GJ$$

$$COS = \$7.13/GJ$$

Total Cost for steam to the RP:

$$Total\ Cost_{RP} = \frac{\$7.13}{GJ} * 3{,}515{,}046\frac{GJ}{year} * 74\%$$

$$Total\ Cost_{RP} = \$18{,}546{,}086/year$$

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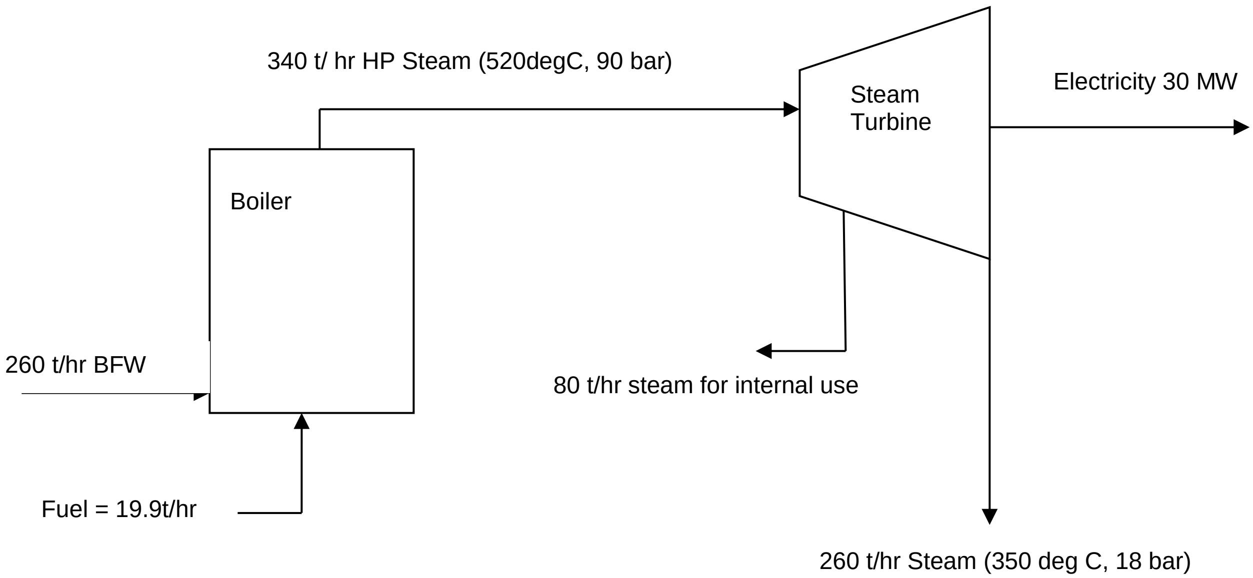
2. COS for a Steam Boiler and Back Pressure Turbine Configuration:
Note: Diagram shows capacity, not throughput



The costs for the system are:

Capital Cost	\$172,000 KCAD - Assume 50% for steam portion & 50% for electricity portion
Operating Cost	\$150 KCAD - Assume 50% for steam portion & 50% for electricity portion
Sustaining Capital	\$5 KCAD - Assume 50% for steam portion & 50% for electricity portion
Maintenance	\$180 KCAD - Assume 50% for steam portion & 50% for electricity portion
Overhead	\$7 KCAD - Assume 50% for steam portion & 50% for electricity portion
Long Term Bond Rate	4% = Return on Capital (ROC)
Depreciation	25 years straight-line

Other information:

Actual throughput	70% of capacity = 182t/hr
Steam Enthalpy	3143 kJ/kg
Energy in BFW	126 kJ/kg
Useful Energy	3143-126 = 3017 kJ/kg
LHV for Natural gas	50 MJ/kg
Price of Natural Gas	\$4/GJ = \$200.8/tonne
Price of Boiler Feed Water	\$3/tonne
Thermal Efficiency	85%

Determine the Level of use (LOU) for the Royalty Project:
Net steam produced = 182 t/hr
Net steam consumed in RP = 126 t/hr

$$LOU_{RP} = \frac{126\ t/hr}{182\ t/hr}$$
$$LOU_{RP} = 69\%$$

Determine the COS calculation:
Determine the Fuel Charged to Steam (FCS) for the year.

$$FCS = \frac{Steam\ (\frac{GJ}{year})}{Thermal\ Efficiency}$$

Where:
Thermal Efficiency = 85%

$$Steam = \frac{\frac{182t}{hr} * \frac{24hr}{d} * \frac{365d}{year} * \frac{1000kg}{t} * \frac{3017kJ}{kg}}{\frac{1000000kJ}{GJ}}$$

$$Steam = 4{,}810{,}063 GJ/year$$

So:

$$FCS = \frac{4{,}810{,}063(\frac{GJ}{year})}{85\%}$$

$$FCS = 5{,}658{,}898\frac{GJ}{year}$$

Convert FCS to t/hr:

$$FCS = \frac{5{,}658{,}898\frac{GJ}{year} * 1000\frac{MJ}{GJ}}{50\frac{MJ}{kg} * 1000\frac{kg}{t}}$$

$$FCS = 113{,}178\ t/year$$
$$FCS = 12.9t/hr$$

Determine the fuel charged to electricity (FCE):

$$FCE = total\ fuel - FCS$$
$$FCE = (70\% * 19.9\frac{t}{hr}) - 12.9\frac{t}{hr}$$

$$FCE = 1.03\frac{t}{hr}$$

Use the FCS to determine fuel costs for steam production:

$$Fuel\ cost_{steam} = \frac{113{,}178\frac{t}{year} * 200.8\frac{\$}{t}}{70\% * 260\frac{t}{hr} * 24\frac{hr}{d} * 365\frac{d}{year}}$$
$$Fuel\ cost_{steam} = \$14.3/tonne$$

Determine the cost of boiler feed water (BFW) used to make steam:

$$BFWcost_{steam} = \frac{\frac{12.9\frac{t}{hr}}{70\% * 19.9\frac{t}{hr}} * 182\frac{t}{hr} * 3\frac{\$}{t} * \frac{24hr}{d} * 365\frac{d}{year}}{70\% * 260\frac{t}{hr} * 24\frac{hr}{d} * 365\frac{d}{year}}$$

$$BFWcost_{steam} = \$2.8/tonne$$

Determine the capital unit charge (CU):

$$CU = \frac{ROC + Depreciation}{actual\ throughput}$$

$$CU = \frac{4\% * \frac{86{,}000{,}000 + 82{,}560{,}000}{2} + 4\% * 86{,}000{,}000}{70\% * 260\frac{t}{hr} * 24\frac{hr}{d} * 365\frac{d}{year}}$$

$$CU = \$4.3/tonne$$

Determine the operating unit charge (OU):

$$OU = \frac{total\ opex\ cost}{actual\ throughput}$$

$$OU = \frac{(\$180{,}000 + \$150{,}000 + \$7{,}000 + \$5{,}000) * 50\%}{70\% * 260\frac{t}{hr} * 24\frac{hr}{day} * 365\frac{d}{year}}$$

$$OU = \$0.1/tonne$$

Determine total COS:

$$COS = Fuel\ cost_{steam} + BFW\ cost + CU + OU$$

$$COS = \frac{\$14.3}{tonne} + \frac{\$2.8}{tonne} + \frac{\$4.3}{tonne} + \frac{\$0.1}{tonne}$$

$$COS = \frac{\$21.5}{tonne}$$

Convert to a GJ basis:

$$COS = \frac{\$21.5/tonne}{3017\frac{kJ}{kg} * 1000\frac{kg}{tonne}} * 1000000kJ/GJ$$

$$COS = \$7.1/GJ$$

Total Cost for steam to the RP:

$$Total\ Cost_{RP} = \frac{\$7.1}{GJ} * 4{,}810{,}063\frac{GJ}{year} * 69\%$$

$$Total\ Cost_{RP} = \$23{,}564{,}499/year$$

Excerpt from the February 2012 Cogeneration Cost Allocation power point presentation

Summary

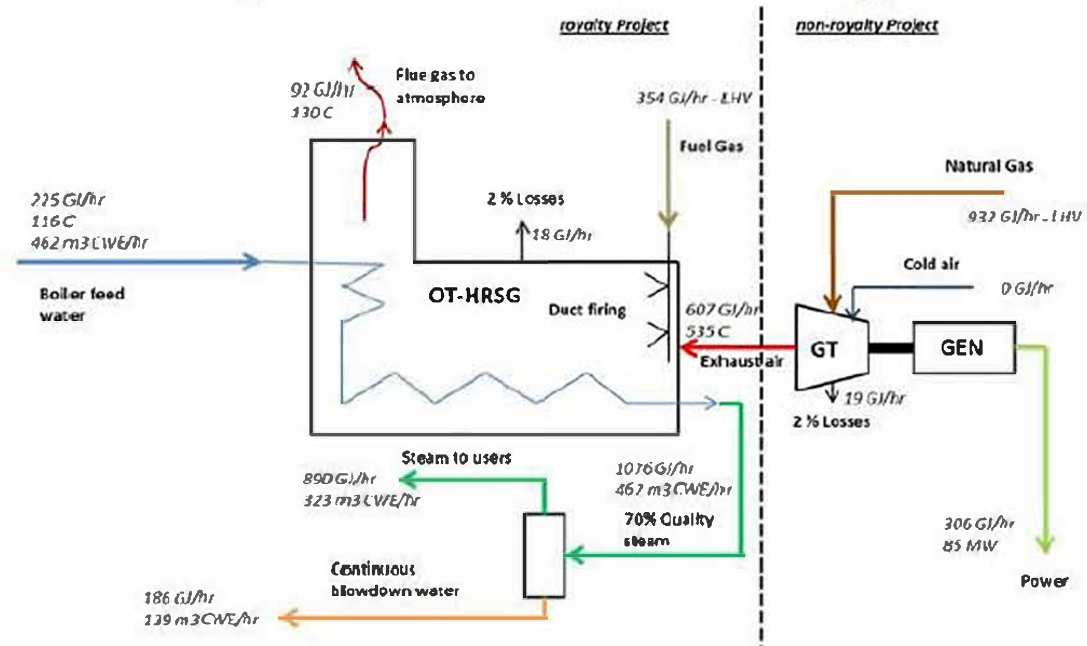
- This presentation provides general information to oil sands royalty Projects that operate cogeneration units for which the cogeneration steam generation is part of the royalty Project and the cogeneration electricity generation is not page of the royalty Project
- Two examples are provided of typical operation of such units:
    - Example 1 represents a highly efficient cogeneration unit which burns clean fuels
      - The water/acid dew point of the flue gases is a function of the sulphur, the hydrogen and the free water content of the fuel
      - The cleaner the fuel, the lower the allowable flue gas temperature, allowing more heat from the combustion flue gases recovered in the economizer to be recovered
      - Boiler Feed Water (BFW) may enter the economizer at lower temperatures.
    - Example 2 represents an efficient cogeneration unit which burns clean fuel in the gas turbine and less clean fuel in the duct burners of the Once Through- Heat Recovery Steam Generators (OT-HRSG)
      - To avoid dew point corrosion , the flue gases cannot be cooled down to the same extent as in example 1
      - Boiler Feed Water (BFW) may enter the economizer at temperatures above the acid dew point.
- The examples demonstrate that efficiencies may vary from Project to Project, and are a function of design and operation of the cogeneration unit.
- Alberta Energy has determined that 85% thermal efficiency of a boiler or HRSG unit will be used to determine the amount of fuel charged to steam, being an allowed cost.

General Allocation and Cost Determination Process

- Components which function primarily to provide useful heat will be allocated to the steam portion of the Cogeneration system (HRSG); components which function primarily to provide electricity will be allocated to the electricity portion (Gas Turbine).
- Shared components and their associated costs will be allocated based on the fuel charged to steam / fuel charged to electricity ratio
- 85% thermal efficiency is used to calculate the total amount of fuel to be allocated to steam (FCS). So in addition to the fuel burned for steam generation in the HRSG, a portion of the fuel burned in the Gas Turbine will be allocated to steam generation.
- Please refer to business rule document

Example 1 GE GT 7 + OT-HRSG

Flue gas outlet OT-HSRG at 130 degrees C



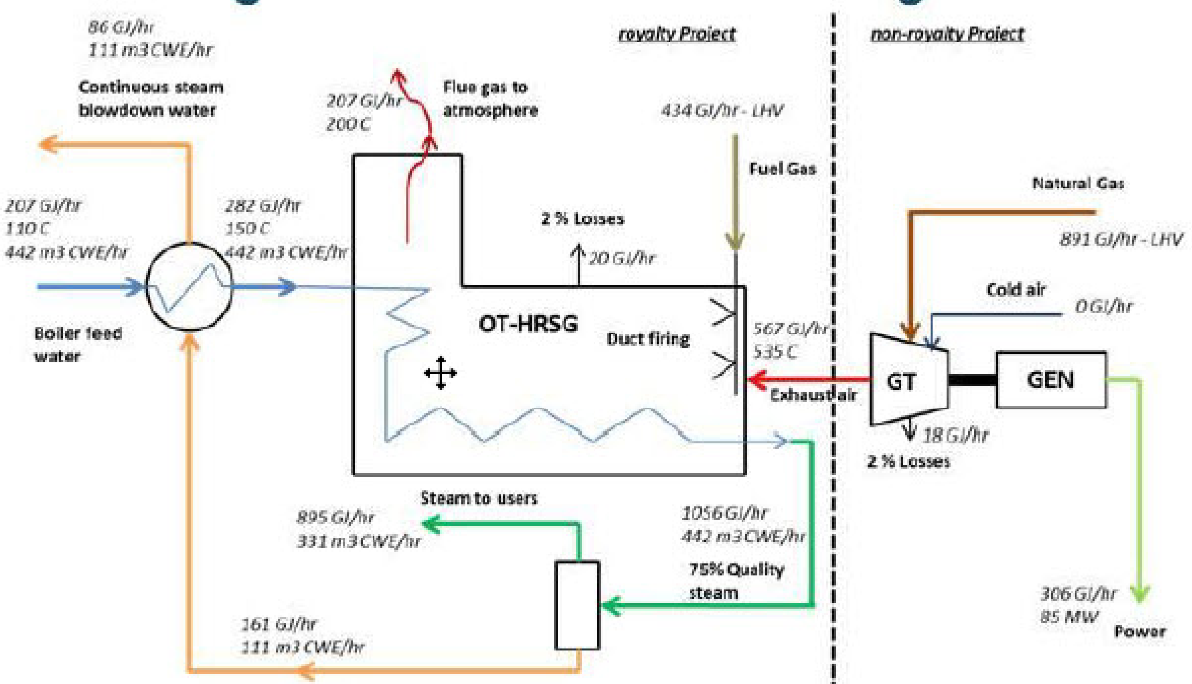
Cogeneration efficiency = (Power + Steam to users + Continuous blowdown water – Boiler feed water) / (Fuel Gas + Natural Gas) * 100 % = 1157 / 1286 * 100% = 90 %

HRSG thermal efficiency = (Steam to users + Continuous blowdown water – Boiler feed water) / (Fuel Gas + Exhaust Air) * 100 % = 851 / 961 * 100% = 89 %

GT electrical efficiency = (Power) / (Natural Gas) * 100 % = 306 / 932 * 100% = 33 %

Example 2 GE GT 7 + OT-HRSG

Flue gas outlet OT-HSRG at 200 degrees C



Cogeneration efficiency = (Power + Steam to users + Continuous blowdown water – Boiler feed water) / (Fuel Gas + Natural Gas) * 100 % = 1080 / 1325 * 100 % = 82 %

HRSG thermal efficiency = (Steam to users + Continuous blowdown water – Boiler feed water) / (Fuel Gas + Exhaust Air) * 100 % = 774 / 1001 * 100 % = 77 %

GT electrical efficiency = (Power) / (Natural Gas) * 100 % = 306 / 891 * 100 % = 34 %

Royalty Regime Calculations

Example 1

- Total fuel = 1286 GJ/hr
- Fuel Charged
  to Steam = 851 / 0.85 GJ/hr
  FCS = 1001 GJ/hr
- Fuel Charged
  to Electricity = 1286 – 1001 GJ/hr
  FCE = 285 GJ/hr
- Allowed Cost for Steam:
  - Fuel gas: 354 GJ / hr
  - Natural gas: 647 GJ / hr (69 % of NG to GT)
- Non-allowed Cost for Electricity
  - Natural gas: 285 GJ / hr
  - Elec-Gen efficiency: 306/285 = 107 %

Example 2

- Total fuel = 1325 GJ/hr
- Fuel Charged
  to Steam = 774 / 0.85 GJ/hr
  FCS = 911 GJ/hr
- Fuel Charged
  to Electricity = 1325 – 911 GJ/hr
  FCE = 414 GJ/hr
- Allowed Cost for Steam:
  - Fuel gas: 434 GJ / hr
  - Natural gas: 477 GJ / hr (54 % of NG to GT)
- Non-allowed Cost for Electricity
  - Natural gas. 414 GJ / hr
  - Elec-Gen efficiency: 306/414 = 74 %

Conclusions

- As part of the generic rules for cost allocation, the DOE has determined that 85% thermal efficiency of a boiler or HSRG unit will be used to determine the amount of fuel charged to steam, being an allowed cost
- This will allow for a reasonable amount of useful heat in the turbine exhaust gases from the gas turbine into the HRSG to be accounted for as fuel. The examples demonstrate that, depending on the actual HRSG efficiency, this then allows for 54 – 69 % of the fuel consumed in the gas turbine to be allocated to steam generation
- The resulting electricity generation remains attractive in terms of fuel efficiency and may even exceed 100%

Government of Alberta – Alberta Energy

Heat Transfer: Business Rules and Sample Calculation

Oil Sands Operations

Allocation and Valuation of Heat Transfer System Costs

Issue

An integrated oil sands operation has a number of process streams which contain thermal energy and transfer considerable heat between the royalty Project and the upgrading units. An appropriate valuation of the useful heat transferred across royalty Project boundaries is required for royalty calculation purposes.

Description

The purpose of this business rule is to define the treatment for thermal energy (or heat) in process streams transmitted between the royalty Project and the non-royalty components of an integrated project. The recognition of net heat transfer as an allowed cost, or other net proceed (ONP) of the royalty Project is governed by the *Oil Sands Allowed Cost (Ministerial) Regulation* (OSACR) and the *Oil Sands Royalty Regulation, 2009* (OSRR09). The fluids utilised for transmission of thermal energy in the Heat Transfer System are usually water, glycol, steam and process streams (generally Hydrocarbons).
The heat contained in process streams can provide services to the royalty Project, upgrader and shared assets in an integrated oil sands development, and may provide significant synergies in the operation of these facilities. These synergies may significantly reduce the total cost of operating the integrated project. For example, without the royalty Project, excess heat from the upgrader would be wasted, and would also impose extra costs on the upgrader's cooling water system. However, this heat can be captured and provided to the bitumen royalty Project, reducing its need to generate that heat using purchased fuels. This is an example of a win-win interaction. Alberta Energy (the Department) believes that these synergistic benefits should be shared between the royalty Project and the upgrader, as would generally be the case in other business relationships.

Scope and Principles of Calculation

This business rule is specifically related to valuing useful heat in process streams transmitted to and from a royalty Project.

1. The Heat Transfer calculation will not include any fuels, or energy sources which are measured and valued individually, including:
    - Steam
    - Electricity
    - Fuels (NG, Fuel Gas, Petroleum Coke, Gasoil, Diesel, Naphtha, etc.) which cross royalty Project boundaries
2. Heat transfer for a stream will be calculated as the change in enthalpy within the stream which is put to some use ("useful heat"). Heat which crosses Project boundaries and is not put to some use to provide a service will not be included. For example, heat in diluted bitumen sold into a pipeline, and heat in water which goes to tailings ponds, are not considered to be useful heat.
3. Heat transfer streams which are not material will not be required in the calculations. A list of typically non-material streams is included in Appendix B – Materiality Issues. The Department will be the final arbiter of what streams are material.
4. The heat will be valued at the Site Wide Thermal Energy Value (SWTEV).
5. The synergy adjusted value of any heat transfer stream will reflect the synergies created between the royalty Project and non-royalty project components of an integrated project.

The major types of process streams we will consider, that transfer heat energy within an integrated oil sands operation, are:

1. Diluted Bitumen (Dilbit) and Diluent streams
2. Product streams
3. Pump Around (PA) streams to the Diluent Recovery Unit (DRU)
4. Process Heat (PH) streams
5. Low Grade Energy (LGE) streams

If the DRU is located within the royalty Project, the product and pump-around streams will cross the royalty Project boundary. If the DRU is located within the upgrader, the dilbit and diluent streams will cross the royalty Project boundary. In both cases, there will be number of process heat, low grade energy and product streams crossing the royalty Project boundary. The major fluid stream flows for typical Heat Transfer System configurations are shown below:

Figure 1 – Heat Transfer System configuration with DRU within royalty Project

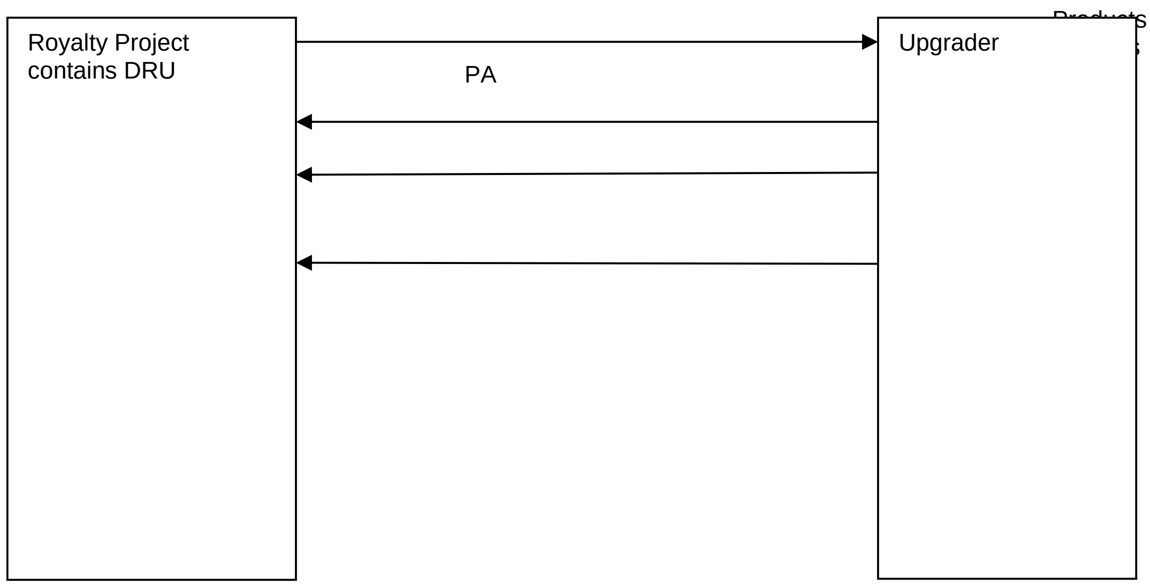
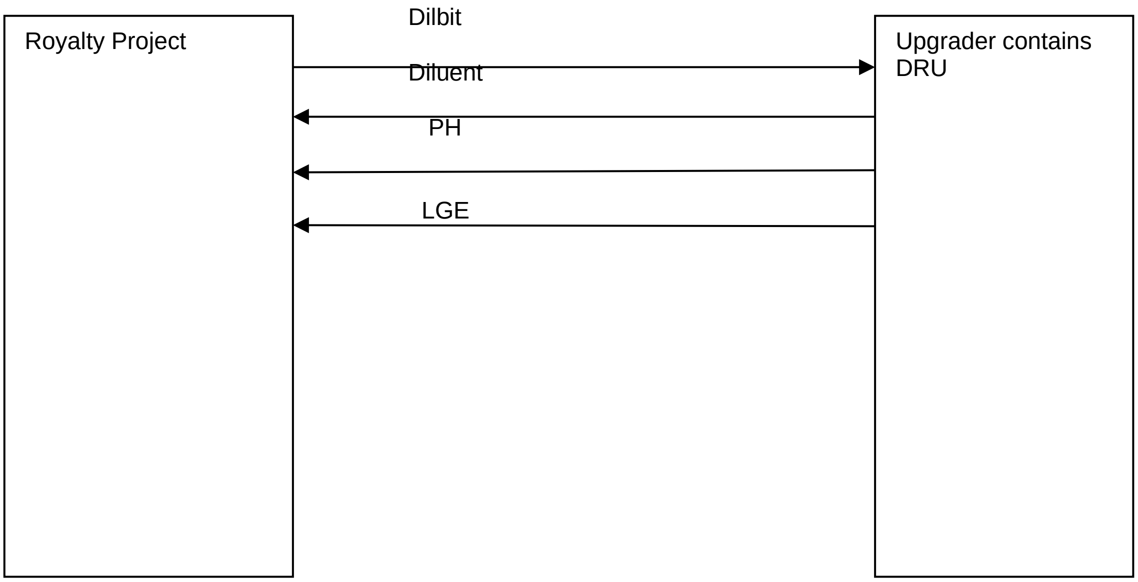


Figure 2 – Heat Transfer System configuration with DRU within Upgrader



Heat Transfer Allocation Methodology

There are a large number of fluid streams flowing between the royalty Project and the upgrader in an integrated oil sands operation. Although the fluid streams may have considerable variation in usage or purpose, our primary concern is the heat transferred by the process streams.

A generic approach to heat transfer valuation will provide a fair and equitable system for measurement and valuation of heat transfer in integrated oil sands operations. The generic mechanism will calculate the amount (change in enthalpy) and the synergy adjusted value of each heat source to provide a fair and reasonable recognition of the value of the service provided to each portion of the integrated project.

Measurement of Heat Transfer

The measurement of heat transfer will be based on the principles set out below:

a) Only process streams crossing the geographic boundary of the royalty Project, or Shared Operations boundary, which have useful heat will be subject to a heat transfer calculation.
b) A reference temperature of 0.0°C will be used for determining the enthalpy in a stream where an output temperature is not available.
c) A net heat transfer rate will be determined for the royalty Project, as an engineering calculation based on normal operations (design).

Mass Flow Rate	$\dot{m}_I$	Design mass flow rate (kg/hr) for stream number "I"
Specific Heat Capacity	c_{pI}	Design specific heat (KJ/kg °C) for fluid stream number "I"
Stream Initial Temperature	T_I	Design temperature (°C) of fluid stream number "I" before transfer
Final Temperature	T_F	Final temperature (°C) of stream after heat transfer (0°C if unknown)
Heat Transfer Rate	$\dot{Q}_I$	Heat transfer rate (KJ/hr) for fluid stream number "I"
Period Heat Transfer	Q_I	Period Heat Transfer (GJ) for fluid steam "I"
Design Bitumen Production Rate	DBP_{RP}	Design bitumen production rate (bbl/hr) for the royalty Project
Net Heat Transfer Value	V_{RP}	Value of heat transfer rate ($/bbl) for the royalty Project

The sign convention for mass flow rate ($\dot{m}_I$) is positive for fluid streams entering the royalty Project and negative for fluid streams exiting the royalty Project. The hourly average heat transfer rate ($\dot{Q}_I$) for a fluid stream is calculated as follows:

$$\dot{Q}_I = \dot{m}_I \times c_{pI} \times (T_I - T_F)$$

$$Q_I\ (GJ) = \{\dot{Q}_I \times 24 \text{ hours} \times 350 \text{ days per year assumed operating time}\}/1{,}000{,}000$$

The Q_I for each stream is based on engineering design parameters, so it should remain constant unless there is a design change in the oil sands operation. It will have to be calculated every 3 years and adjusted every time there is a major change to the design or operating configuration of the project pertaining to heat energy being transferred between the royalty Project and the non-royalty project.

Valuation of Heat Transfer

To put a monetary value on the heat transferred between the royalty Project and the non-royalty project components requires two elements: a value (price) for the heat transferred, and a "synergy factor" which will allocate the total value of the heat transferred between the royalty Project and the rest of the integrated project.

Thermal Energy Valuation – Determining a Value for Heat Transfer

The value of heat transferred in process streams between the parts of an integrated project will be deemed to be equal to the weighted average value, in $/GJ, of all the fuels used to generate heat on the integrated project. We will call this the Site Wide Thermal Energy Value (SWTEV). Details of the SWTEV calculation are included in Appendix A of this document, and the calculation details are in Appendix C.

The Synergy Factor – Sharing the Costs or Revenues of Heat Transfer

Consider the case where an upgrader provides process heat (in the form of a hot water stream) to the royalty Project.

For an upgrader alone, the waste heat which is generated as a by-product of upgrading operations would have no value, and would also be an additional cost to the cooling water system. This would give an effective value of less than zero for the waste heat.

For a royalty Project alone, the heat which provides a service to the royalty Project would need to be generated via purchased fuel, at a cost of the SWTEV per GJ of heat used.

In a case like this, where both the upgrader and royalty Project benefit from the transfer of heat, we need to determine what portion of the value of the heat obtained from the upgrader should be treated as a cost to the royalty Project. To do this, we apply a synergy factor to the value. The synergy factor has been established by the Minister as 0.66. That is, the upgrader is seen to capture 66% of the value of the synergy. In other words, if 1 GJ of heat is transferred to the royalty Project, and the SWTEV is $1.00/GJ, then the allowed "cost" to the royalty Project for that heat will be $0.66. Conversely, if the 1 GJ of heat were transferred from the royalty Project to the upgrader, the royalty Project would be assigned $0.66 of other net proceeds ("ONP") as a result of the heat transfer.

In a case where the benefit of heat transfer accrues to only one side of the exchange, the synergy factor will not be applied.

Implementation
To implement the heat transfer valuation business rules at integrated oil sands Projects, the following information must be provided to the Department:

5. Process Flow Diagrams (PFD)
6. Stream Property Tables (SPT)
7. Battery Limit Tables
8. Thermal or Heat Balances

This information will need to be provided to the Department when an application is submitted for an expansion or new royalty Project at an integrated facility requiring heat transfer valuation, or when the Department requests such information in the course of its audits or site reviews.
The Department will review the information it has on file and contact the operator to obtain additional information required for the valuation of heat transfer in existing Projects. The operator may submit a proposal for defining the scope of the Heat Transfer System and what costs need to be allocated within a reasonable time after the Department has made such a request. The Department will review the proposal and identify any corrections or changes to the operator. The Department may perform an audit of the allocations at any time including any aspect of the valuation it deems appropriate to be satisfied that the results are acceptable.
The determination of which thermal energy streams will be included in the calculation will be subject to an engineering review by the Minister.

Simple Business Rule Statement Regarding Heat Transfer:

1. The cost of the Heat Transfer will be calculated based on:
   - The net useful thermal energy that crosses royalty Project boundaries or Shared Operations boundaries.
   - The synergy factor
   - The site-wide weighted average price of fuel sources that provide thermal energy to any part of the integrated facility (i.e. natural gas, syngas, off-gas).

2. The synergy adjusted (where appropriate) heat transfer for each stream will be summed to yield the total net synergy-adjusted heat transfer between the royalty Project and non-royalty project components of the integrated operation.

3. This amount will be divided by the designed bitumen production capacity of the royalty Project, to give a net heat transfer rate per m^3 of bitumen.

4. This per m^3 rate will be multiplied by the SWTEV to give a heat transfer value per m^3 of bitumen.

5. That value will be multiplied by the volume of bitumen delivered to the royalty calculation point (RCP) in the Period to determine the cost (or ONP amount) for heat transferred to (or from) the royalty Project in the Period.

Appendix A - Site Wide Thermal Energy Value (SWTEV)

A number of different fuel sources may be utilised to generate thermal energy within an integrated oil sands operations. Although fuel sources may have considerable variation in quality or thermal efficiency, our primary concern is with the cost of thermal energy provided by fuel source.
The site wide thermal energy value will be calculated, for each Period, according to the method shown below:

a) All fuel sources used to generate thermal energy in an integrated oil sands operation will be valued. Fuel sources sent to other facilities will not be considered.

b) The arm's length and non-arm's length cost rules in the *Oil Sands Allowed Cost (Ministerial) Regulation* will be utilized in determining the price of a fuel source for the heat transfer calculation.

A site wide thermal energy value will be established for the integrated project for each Period.

Price	P_I	Period average price ($/GJ) for fuel source number "I"
Thermal Energy Quantity	E_I	Period thermal energy (GJ) generated from fuel source number "I"[Low Heating Value (LHV)]
Thermal Energy Cost	C_I	Period cost ($) for thermal energy generated from fuel source number "I"
Site Wide Thermal Energy Value	SWTEV	Period weighted average price ($/GJ) for thermal energy generated on the integrated project.

The cost in each Period (C_I) for thermal energy generated from a fuel source is determined as follows:

$C_I = P_I \times E_I$

The annual weighted average price (SWTEV) for thermal energy is calculated as follows:

$SWTEV = \sum_{I=1} (C_I) / \sum_{I=1} (E_I)$

This site wide thermal energy value will have to be calculated for each Period.

Appendix B – Materiality Issues

In determining whether heat in a process stream is significant enough to be incorporated in the heat transfer calculation, the following principles will be applied:

1) Heat transfer in instrument air, process air or utility air will not be analyzed if there is no attempt to transfer value within a Project and the air crosses the boundary of a royalty Project at normal temperature for that substance. As these substances are typically used for lay-up of equipment or for maintenance purposes, we will not attribute any value to the heat transfer.
2) Heat transfer in nitrogen circuits will not be assessed if there is no attempt to transfer economic value, the nitrogen is transferred at a typical temperature for that use, and the nitrogen is being used for maintenance or turnaround reasons.
3) Flare system energy transfers will only be considered if there is a system in place to recover energy from the flared gas for use in the operation of the royalty Project.
4) No natural gas used in the flare pilots will be considered as an energy transfer unless the flare system serves only the royalty Project, and no upgrader relief is connected to the flare stack.
5) Condensate return or boiler feed water energy will only be considered in the calculation of net heat produced by a steam boiler and not as a process heat transfer unless some process heat from the royalty Project is transferred to the non-royalty project.
6) Boiler make-up water for a treated water system will not be considered to be a transfer of energy if the treated water leaves the water treatment plant at a normal temperature and there is no attempt to absorb heat energy to transfer economic value across a royalty Project boundary.
7) Start-up lines or lines that in normal operations are normally closed will not be assessed. If abnormal operation is extended for more than 30 days, the Department is to be notified of the new configuration and any engineering design changes.
8) The Department will assess heat transfers in diluent make-up but will not be obligated to consider the flow labelled diluent make-up as the actual make-up. This flow may actually be diluent slippage and the make-up amount will be that amount assessed by the AER as make-up.
9) Process water flows, treated water at a thermal in-situ (SAGD or CSS) Project, and other waste water flows may be assessed for materiality in relation to the amount of energy transferred using these streams, but generally are not to be considered in the assessment of heat transfer.
10) The materiality thresholds and associated considerations will apply to the materiality of all heat transfers across royalty Project boundaries.
11) Engineering studies of heat transfer at a royalty Project may consider directly related flows where there is an offsetting heat transfer. The Department will be responsible for determining the scope of any such study and any subsequent determination of materiality.
12) The Department must be notified of any engineering or operational changes that affect heat transfer calculations at a royalty Project within one month of the operator being aware of the change or impending change.
13) The Department will not consider energy transfers from condensers or cooling tower circuits within steam turbine installations or within cogeneration plants. As the Department has already made allowance for losses at these facilities, this would result in double counting. No duplication of costs is allowed.
14) Utility Steam will have to be metered when allocating utility steam use to royalty Project and non-royalty project purposes, and will not be part of the heat transfer calculation.
15) All information the Department determines it requires, related to processing, reviewing, calculating or otherwise, to complete a heat transfer assessment must be provided or the Minister will determine the value of the heat transfer.
16) All access to physical elements or process information that the ADOE determines is required to complete a heat transfer assessment must be provided, or the Minister will determine the value of the heat transfer.

Appendix C - Heat Transfer Examples

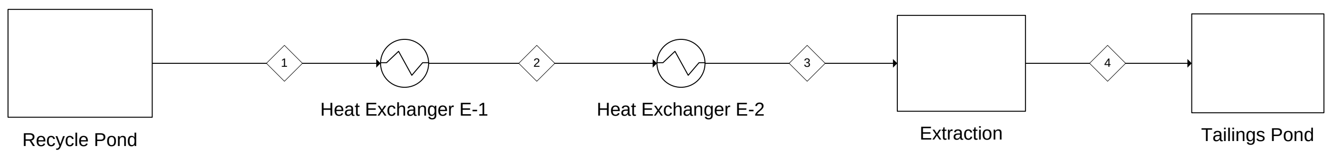
Step 1 – Heat Transfer Calculation

The value of useful heat transferred between the royalty Project and the non-royalty project parts of an integrated operation needs to be calculated. To do this, each material process stream that transfers heat across the royalty Project boundary will be evaluated and used in calculating the net flow of energy. Part A of this example will calculate the synergy adjusted heat transfer (enthalpy) from the non-royalty project to the royalty Project, while Part B will show the synergy adjusted heat transfer (enthalpy) from the royalty Project to the upgrading operations.
The process will be as follows (all based on standard operating conditions):

1. Identify the net heat transfer rate for each stream, assuming full enthalpy transfer between starting, and final temperatures for the stream which is transferring heat.
2. Apply the Synergy Factor for each heat transfer rate, to obtain the synergy adjusted heat transfer rate.
3. Sum the synergy adjusted heat transfer rates entering the royalty Project (+), and leaving the royalty Project (-) to get a net heat transfer rate.
4. Compare the net heat transfer rate to the bitumen production rate, to obtain a net heat transfer rate per m^3 of bitumen for each Project. This rate is unlikely to change until a significant change occurs to the Project.
5. Determine the SWTEV for each Project, each Period.
6. Multiply the net heat transfer rate per m^3 x the SWTEV x actual bitumen production (delivered to the RCP) for the Period to determine the allowed cost (+), or ONP (-) for the Period.

Part A: Energy from the Non Royalty project to the Royalty Project: Recycle Water

Recycle Water



Stream Property Table				
Stream #	***Description***	***Flow Rate (kg/hr)***	***Temperature (˚C)***	***Cp (kJ/kg˚C)***
1	Recycle Water	10,000,000	15	4.19
2	Recycle Water	10,000,000	35	4.19
3	Recycle Water	10,000,000	75	4.19
4	Water to Tailings Pond	10,000,000	40	4.19

Water from the recycle pond cools other streams through two heat exchangers before being sent to extraction as warm water at 75 ˚C. The warm water is used in the extraction process and subsequently run down into the tailings pond at a temperature of 40 ˚C. Therefore the actual energy used by extraction is the energy in the water from 75 ˚C to 40 ˚C. This heat is considered to be “useful”.

The water in the tailings pond will cool down to 15 ˚C due to evaporative losses and heat transfer to colder ambient air. It is recycled back to the recycle pond for re use in extraction. Although this amount of heat lost has to be made up by the heat exchangers from the Non Royalty Project, it not considered “useful” heat because the Royalty Project does not benefit from this heat.
The heat transfer calculation is:

$$\dot{Q}_{RW} = \dot{m} * C_p * \Delta T$$

Where:
$\dot{Q}$ = Heat transfer rate (kJ/hr)
SA$\dot{Q}$ = Synergy Adjusted heat transfer rate (KJ/hr)
$\dot{m}$ = mass flow rate (kg/hr)
C_p = specific heat capacity (kJ/kg˚C)
ΔT = the change in temperature (˚C)
RW = Recycle Water

The <u>total</u> amount of heat transferred from the Non Royalty project to the Royalty Project is:

$$\dot{Q}_{RW,total} = 10{,}000{,}000\, kg/hr * 4.19\, kJ/kg^{\circ}C * (75^{\circ}C - 15^{\circ}C)$$
$$\dot{Q}_{RW,total} = 2{,}514{,}000{,}000\ kJ/hr$$
$$\dot{Q}_{RW,total} = 2{,}514\ GJ/hr$$

The <u>useful</u> heat transferred from the Non Royalty project to the Royalty Project is:

$$\dot{Q}_{RW,ss} = 10{,}000{,}000\,kg/hr * 4.19\,kJ/kg^{\circ}C * (75^{\circ}C - 40^{\circ}C)$$
$$\dot{Q}_{RW,ss} = 1{,}466{,}500{,}000\ kJ/hr$$
$$\dot{Q}_{RW,ss} = 1{,}467\ GJ/hr$$

Apply the 66% Synergy Factor:

$$SA\dot{Q}_{RW,ss} = 1{,}467\ GJ/hr * 66\%$$
$$SA\dot{Q}_{RW,ss} = 968\ GJ/hr$$

The amount of heat transferred which is not put use and there for is <u>not</u> considered "<u>useful</u>":

$$\dot{Q}_{RW,nu} = 10{,}000{,}000\,kg/hr * 4.19\,kJ/kg^{\circ}C * (40^{\circ}C - 15^{\circ}C)$$
$$\dot{Q}_{RW,nu} = 1{,}047{,}500{,}000\ kJ/hr$$
$$\dot{Q}_{RW,nu} = 1048\ GJ/hr$$

In summary:

Amount of heat transferred from Non Royalty project to Royalty Project: 2,514 GJ/hr

Not considered useful: 1,048 GJ/hr

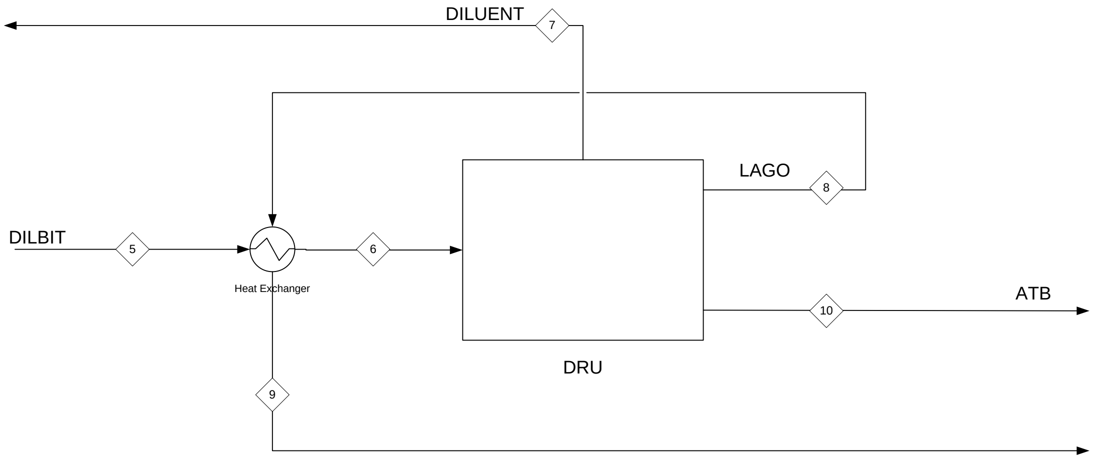
Considered useful: 1,467 GJ/hr

Synergy Adjusted heat transfer rate: 968 GJ/hr

$$SA\dot{Q}_{RW,total} = SA\dot{Q}_{RW,ss} = 968\ GJ/hr$$

Part B: Energy from the Royalty Project to the Non Royalty project: DRU in royalty Project.

DRU



Stream Property Table				
Stream #	**Description**	**Flow Rate (kg/hr)**	**Temperature (˚C)**	**Cp (kJ/kg˚C)**
5	Dilbit		50	
6	Dilbit		70	
7	Diluent		200	
8	LAGO	100,000	250	2.4
9	LAGO	100,000	220	2.4
10	ATB	600,000	200 - 350	2.3 - 2.7

Energy from the DRU is going to the Non Royalty project in both the LAGO (light atmospheric gas oils) and ATB (atmospheric topped bitumen) streams. As the DRU is increasing the temperature of the diluted bitumen, the LAGO's and ATB are gaining energy in addition to the diluent which is being flashed off. So, for the purposes of this heat transfer calculation, there is a synergy which exists, from the input temperature of the dilbit, to the temperature of the diluent out of the tower. In this example diluent exits the towers at an average of 200˚C, so the synergy factor will be applied for the energy from 70˚C to 200˚C. Any additional energy added to the DRU is for the sole benefit of the upgrader, and therefore no synergy exists.

The sample calculations for the ATB and LAGO streams are:

Atmospheric Topped Bitumen

Two calculations are required, one for the portion of energy that is synergy shared and one for the portion that is not.

The portion that is synergy shared (ss):

$$\dot{Q}_{ATB,ss} = \dot{m} * C_p * \Delta T$$

$$\dot{Q}_{ATB,ss} = 600{,}000\, kg/hr * 2.3\, kJ/kg^{\circ}C * (200^{\circ}C - 70^{\circ}C)$$

$$\dot{Q}_{ATB,ss} = 179{,}400{,}000\, kJ/hr$$

$$\dot{Q}_{ATB,ss} = 179.4\, GJ/hr$$

Apply the 66% synergy Factor:

$$SA\dot{Q}_{ATB,ss} = 179.4\, GJ/hr * 66\%$$

$$SA\dot{Q}_{ATB,ss} = 118.4\, GJ/hr$$

The portion of the ATB that has no synergy (ns):

$$\dot{Q}_{ATB,ns} = \dot{m} * C_p * \Delta T$$
$$\dot{Q}_{ATB,ns} = 600{,}000\, kg/hr * 2.7\, kJ/kg^{\circ}C * (350^{\circ}C - 200^{\circ}C)$$
$$\dot{Q}_{ATB,ns} = 243{,}000{,}000\, kJ/hr$$
$$\dot{Q}_{ATB,ns} = 243\, GJ/hr$$

The total synergy adjusted enthalpy transferred from the Royalty Project to the upgrader from the ATB stream is:

$$SA\dot{Q}_{ATB,total} = SA\dot{Q}_{ATB,ss} + \dot{Q}_{ATB,ns}$$
$$SA\dot{Q}_{ATB,total} = 118.4\, GJ/hr + 243\, GJ/hr$$
$$SA\dot{Q}_{ATB,total} = 361.4\, GJ/hr$$

Light Atmospheric Gas Oils

The LAGO has a pump-around that is heating Dilbit on the Royalty Project side. The energy transferred to the dilbit is not providing a service to the upgrader and therefore the energy left in the LAGO after the heat exchanger (T=220˚C) will be the starting point of the calculation. Similar to the ATB, two calculations are required for the LAGO to determine the heat transfer.

The portion that is synergy shared (ss):

$$\dot{Q}_{LAGO,ss} = \dot{m} * C_p * \Delta T$$
$$\dot{Q}_{LAGO,ss} = 100{,}000\, kg/hr * 2.4\, kJ/kg^{\circ}C * (200^{\circ}C - 70^{\circ}C)$$
$$\dot{Q}_{LAGO,ss} = 31{,}200{,}000\, kJ/hr$$
$$\dot{Q}_{LAGO,ss} = 31.2\, GJ/hr$$

Apply the 66% synergy Factor:

$$SA\dot{Q}_{LAGO,ss} = 31.2\, GJ/hr * 66\%$$
$$SA\dot{Q}_{LAGO,ss} = 20.6\, GJ/hr$$

The portion of the LAGO that has no synergy (ns):

$$\dot{Q}_{LAGO,ns} = \dot{m} * C_p * \Delta T$$
$$\dot{Q}_{LAGO,ns} = 100{,}000\, kg/hr * 2.4\, kJ/kg^{\circ}C * (220^{\circ}C - 200^{\circ}C)$$
$$\dot{Q}_{LAGO,ns} = 4{,}800{,}000\, kJ/hr$$
$$\dot{Q}_{LAGO,ns} = 4.8\, GJ/hr$$

The total synergy adjusted heat transfer from the royalty Project to the upgrader from the LAGO stream is:

$$SA\dot{Q}_{LAGO,total} = SA\dot{Q}_{LAGO,ss} + \dot{Q}_{LAGO,ns}$$
$$SA\dot{Q}_{LAGO,total} = 20.6\, GJ/hr + 4.8\, GJ/hr$$
$$SA\dot{Q}_{LAGO,total} = 25.4\, GJ/hr$$

Therefore, the total synergy adjusted heat transfer from the DRU to the Non Royalty project is:

$$SA\dot{Q}_{DRU} = SA\dot{Q}_{ATB,total} + SA\dot{Q}_{LAGO,total}$$
$$SA\dot{Q}_{DRU} = 361.4\, GJ/hr + 25.4\, GJ/hr$$
$$SA\dot{Q}_{DRU} = 386.8\, GJ/hr$$

Now, determine the synergy adjusted net heat transfer into/out of the Royalty Project (RP). Assume energy going into the Royalty Project is positive (+) and energy leaving the Royalty Project is negative (-), then:

$$SA\dot{Q}_{RP\ total} = SA\dot{Q}_{RW,SS} - SA\dot{Q}_{DRU,total}$$
$$SA\dot{Q}_{RP\ total} = 968\,GJ/hr - 386.8\,GJ/hr$$
$$SA\dot{Q}_{RP\ total} = 581.2\,GJ/hr$$

The net heat transfer is 581.2 GJ/hr from the Non Royalty project to the Royalty Project.
If the design capacity of the Royalty Project, under normal operating conditions, is 150,000 bbl/d of bitumen, the synergy adjusted net heat transfer per barrel is:

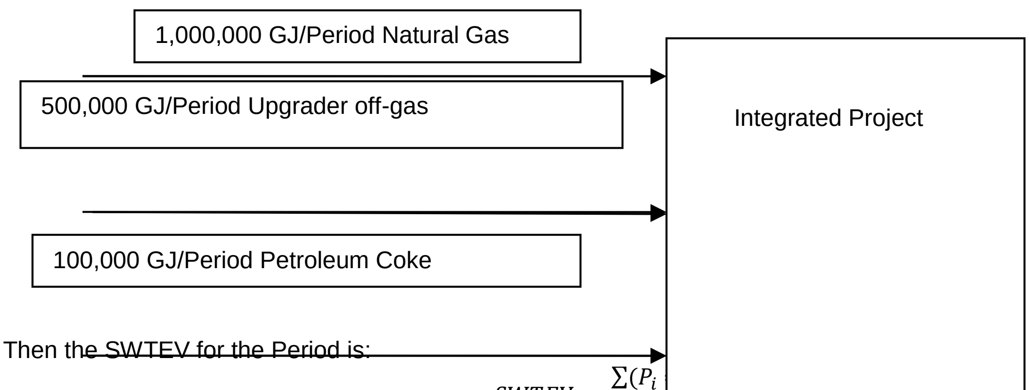
$$SA\dot{Q}_{total\ per\ barrel} = \frac{581.2\,GJ/hr * 24\,hr/day}{150,000\,bbl/day}$$
$$SA\dot{Q}_{total\ per\ barrel} = 0.093\,GJ/bbl$$

= 0.585 GJ / m^3 of bitumen.
Having the heat transfer rate expressed on a per volume basis at normal operating conditions will eliminate any changes due to fluctuations in production.

Step 2: SWTEV Calculation

The SWTEV is an average value, per Period, of all the fuels used to generate heat on an integrated project.

If an integrated project consumes energy from the following fuels:



Then the SWTEV for the Period is:

$$SWTEV = \frac{\sum(P_i}{\sum E_i}$$

Where:
P = Price for fuel source ($/GJ)
E = Thermal energy generated from fuel source (GJ/Period, Low Heating Value)

Assuming, for the purpose of SWTEV calculation:

The cost to the project, per the *Oil Sands Allowed Cost (Ministerial) Regulation*, for natural gas is $6.35 / GJ. The Alberta Reference Price (ARP) for natural gas is 6 $/GJ, so the price of upgrader off-gas is 90% of ARP = 5.4 $/GJ, and

The price of petroleum coke is 0 $/GJ

Then the SWTEV is:

$$SWTEV = \frac{(1{,}000{,}000\ GJ\ /year * 6.35\ \$/GJ) + (500{,}000\ GJ/year * 5.4\ \$/GJ)}{1{,}000{,}000\ GJ/year + 500{,}000\ GJ/year}$$

$$SWTEV = \frac{(6{,}350{,}000\ \$\ /year) + (2{,}700{,}000\ \$/year)}{1{,}500{,}000\ GJ/year}$$

$$SWTEV = \frac{9{,}050{,}000\ \$/year}{1{,}500{,}000\ GJ/year}$$

$$SWTEV = 6.03\ \$/GJ$$

Using the calculated net heat transfer value of 0.0585 GJ/m^3 from Step 1 and the SWTEV of 6.03 $/GJ from Step 2 we can calculate the value of the heat transferred to the royalty Project, which will be an allowed cost of the royalty Project.

$$Value = Allowed\ Cost = SAQ_{total\ per\ barrel} * SWTEV * Period\ production$$

For this example: (Assuming that the Actual Production for the Period was 50 Million barrels of bitumen (7.946 million m^3), and the calculated value for SWTEV for the Period was $6.03):

$$Allowed\ Cost = 0.585\ GJ/m3 * 6.03\ \$/GJ * (7.946\ million\ m3)$$

$$Allowed\ Cost\ for\ Heat\ Transfer = \$28{,}029{,}912$$

So the allowed cost to the Royalty Project for the Period would be $28,029,912.

Government of Alberta – Alberta Energy

Cost of Service Calculations

Oil Sands Operations

Overview

When an asset provides a Basic Service to a Project at Non-Arm's Length (NAL), or for Goods and Non-Basic services where a fair market value (FMV) cannot be determined, a Cost of Service (COS) calculation will be required.

Specifically, COS calculations will be required where:

1. NAL Goods or services are provided by non-Project Assets to a Project, to determine Allowed Costs of the Project; and
2. NAL Goods or services are provided by Project Assets to operations outside the Project, to determine other net proceeds (ONP) for the Project.

Cost of Service Calculation - Key Principles

1) Annual Cost of Service Calculation

An annual COS per unit charge for an asset with a readily identifiable measure of capacity and throughput is calculated by summing the per unit capital charge and the per unit operating charge.

Annual Per Unit Cost of Service =

$$\left[\frac{\text{Capital Charge}}{\text{Capacity}} + \frac{\text{Operating Charge}}{\text{Throughput}} \right]$$

Where:

Capital Charge = Annual Depreciation Amount + Annual Return on Capital Amount
Capacity = the ***Greater*** of 75% of Design Capacity or actual measured Throughput

Operating Charge = Annual Operating Costs Incurred
Throughput = Annual units produced by the asset, as determined by measured use

Where a non-Project COS asset provides services to a royalty Project, the annual allowed cost for the Project is this per unit COS charge multiplied by the number of units provided to the Project.

Where a Project COS asset provides services to non-Project operations, the annual ONP attributed to the Project is this per unit COS charge multiplied by the number of units supplied by the Project.

For assets which do not have a readily identifiable measure of capacity or throughput, the COS calculation will simply determine an annual amount – Capital Charge + Operating Charge – which will be allocated between Project and non-Project use by the appropriate methodology.

For specified assets which have been oversized as good engineering practice (for integrated Projects these would include: steam generation, raw water treatment, and boiler feed water treatment), the COS calculation will always be determined based on actual throughput and not design capacity.

For pre-payout Projects, an estimate of the annual COS charge may be divided by 12 to obtain the monthly COS for an asset, with a true-up to actual amounts included in the end of period statement (EOPS).

2) Determining Cumulative Capital Cost

The Cumulative Capital Cost (CCC) is used:

a. when determining whether or not capital additions are treated as capital or as operating costs for the purpose of COS calculations;
b. as the basis for calculating the annual depreciation amount. The CCC for the year in which a capital asset or engineering system is first commissioned is the original capital cost of the asset incurred prior to the first day of that calendar year (including any capital additions and less any retirements before that date.) Any capital additions or retirements made during the commissioning year, or any subsequent year, will be added to or subtracted from the CCC value effective on January 1 of the following year.

3) Determining Operating and Capital Costs

The CCC amount will be used when determining whether the costs of a capital addition to an asset or engineering system are considered as operating costs or included as capital for the purposes of COS calculation. If the cost of an addition is greater than 10% of the CCC, it will be treated as capital. If the cost is less than or equal to 10% of the CCC, it will be considered an operating cost in the year it is incurred.

True operating costs will not be capitalized even if they exceed 10% of the CCC in any year. Examples of such costs include energy costs, annual taxes including property taxes, chemical costs, annual environmental fees or levies, and maintenance costs. *(Note, this list is not all inclusive.)*

4) Calculating the Annual Depreciation Amount and Return on Capital

Under the new COS rules, straight line depreciation over 25 years, with zero salvage value, is the default calculation method. The annual depreciation amount is calculated as 4% of the CCC.

The Annual Return on Capital amount will be calculated by multiplying the average capital amount employed for the year (the sum of the initial capital book value [Initial Capital] plus the ending book value [End Capital], divided by two) by the rate of return. The Rate of Return on Capital (ROC) is established as the Long Term Bond Rate (LTBR). This rate will apply to the provision of both basic and non- basic services. The choice of this rate provides no incentive for disputes over whether the COS asset is providing a basic or non-basic service, and no financial incentive for operators to take the asset out of the Project. The exception to this ROC default rule is non-basic (sales) pipelines. In calculating the ROC for such lines, a deemed 45% / 55% debt / equity split is assumed. The return on debt is set at the LTBR+1%, and the return on equity at the NEB multi-pipeline rate of return.

First year rule:

In the year in which a capital or engineering system is first commissioned, pro-rating is required to calculate the annual depreciation and ROC amounts. They are pro-rated by the ratio of: the remaining number of days in the calendar year following the commissioning date to 365.

5) Calculating the Operating Charge

The Operating Charge is the sum of all eligible operating costs incurred by the COS asset. The per unit annual operating charge is the Operating Charge divided by the measured throughput of the COS asset.

Example 1: An asset with an annual capacity of 1000 units and throughput of 800 units. In year 1, a capital amount of $100 million is spent before January 1. On April 1 of the same year, the asset is officially commissioned. Between January 1 and April 1, an additional $50 million has occurred as capital expenditure. **Figure 1** illustrates this example.

Figure 1

$$\left\{ \frac{\text{Capital Charge}}{\text{Capacity}} + \frac{\text{Operating Charge}}{\text{Throughput}} \right\} \cdot \text{\# Units used in the royalty Project (Allowed Cost) or \# of units for non project use (ONP)}$$

Max Design Capacity	1000	Asset Commission Date	April 1st of year 1
Throughput	800	Asset expenses by Jan 1 of the commission year	$100,000,000
LTBR	4%	Asset Initial Capital Cost by asset commission date	$150,000,000

Year	Cumulative Capital Cost	Initial Capital	Straight Line Dep'n	End Capital	Return on Capital (4%)	Annual Capital Charge	Annual Capital Charge per unit	Annual Operating Charge	Annual Operating Charge per Unit	Annual COS per unit	Capital Addition/Retirement
1	$ 100,000,000	$ 100,000,000	$ 3,013,699	$ 96,986,301	$ 2,968,287	$ 5,981,985	$ 7,477	$ 500,000	$ 625	$ 8,102	$ 50,000,000
2	$ 150,000,000	$ 146,986,301	$ 6,000,000	$ 140,986,301	$ 5,759,452	$ 11,759,452	$ 14,699	$ 1,000,000	$ 1,250	$ 15,949	
3	$ 150,000,000	$ 140,986,301	$ 6,000,000	$ 134,986,301	$ 5,519,452	$ 11,519,452	$ 14,399	$ 1,000,000	$ 1,250	$ 15,649	
4	$ 150,000,000	$ 134,986,301	$ 6,000,000	$ 128,986,301	$ 5,279,452	$ 11,279,452	$ 14,099	$ 1,000,000	$ 1,250	$ 15,349	
5	$ 150,000,000	$ 128,986,301	$ 6,000,000	$ 122,986,301	$ 5,039,452	$ 11,039,452	$ 13,799	$ 1,000,000	$ 1,250	$ 15,049	
6	$ 150,000,000	$ 122,986,301	$ 6,000,000	$ 116,986,301	$ 4,799,452	$ 10,799,452	$ 13,499	$ 1,000,000	$ 1,250	$ 14,749	
7	$ 150,000,000	$ 116,986,301	$ 6,000,000	$ 110,986,301	$ 4,559,452	$ 10,559,452	$ 13,199	$ 1,000,000	$ 1,250	$ 14,449	
8	$ 150,000,000	$ 110,986,301	$ 6,000,000	$ 104,986,301	$ 4,319,452	$ 10,319,452	$ 12,899	$ 1,000,000	$ 1,250	$ 14,149	
9	$ 150,000,000	$ 104,986,301	$ 6,000,000	$ 98,986,301	$ 4,079,452	$ 10,079,452	$ 12,599	$ 1,000,000	$ 1,250	$ 13,849	
10	$ 150,000,000	$ 98,986,301	$ 6,000,000	$ 92,986,301	$ 3,839,452	$ 9,839,452	$ 12,299	$ 1,000,000	$ 1,250	$ 13,549	
11	$ 150,000,000	$ 92,986,301	$ 6,000,000	$ 86,986,301	$ 3,599,452	$ 9,599,452	$ 11,999	$ 1,000,000	$ 1,250	$ 13,249	
12	$ 150,000,000	$ 86,986,301	$ 6,000,000	$ 80,986,301	$ 3,359,452	$ 9,359,452	$ 11,699	$ 1,000,000	$ 1,250	$ 12,949	
13	$ 150,000,000	$ 80,986,301	$ 6,000,000	$ 74,986,301	$ 3,119,452	$ 9,119,452	$ 11,399	$ 1,000,000	$ 1,250	$ 12,649	
14	$ 150,000,000	$ 74,986,301	$ 6,000,000	$ 68,986,301	$ 2,879,452	$ 8,879,452	$ 11,099	$ 1,000,000	$ 1,250	$ 12,349	
15	$ 150,000,000	$ 68,986,301	$ 6,000,000	$ 62,986,301	$ 2,639,452	$ 8,639,452	$ 10,799	$ 1,000,000	$ 1,250	$ 12,049	
16	$ 150,000,000	$ 62,986,301	$ 6,000,000	$ 56,986,301	$ 2,399,452	$ 8,399,452	$ 10,499	$ 1,000,000	$ 1,250	$ 11,749	
17	$ 150,000,000	$ 56,986,301	$ 6,000,000	$ 50,986,301	$ 2,159,452	$ 8,159,452	$ 10,199	$ 1,000,000	$ 1,250	$ 11,449	
18	$ 150,000,000	$ 50,986,301	$ 6,000,000	$ 44,986,301	$ 1,919,452	$ 7,919,452	$ 9,899	$ 1,000,000	$ 1,250	$ 11,149	
19	$ 150,000,000	$ 44,986,301	$ 6,000,000	$ 38,986,301	$ 1,679,452	$ 7,679,452	$ 9,599	$ 1,000,000	$ 1,250	$ 10,849	
20	$ 150,000,000	$ 38,986,301	$ 6,000,000	$ 32,986,301	$ 1,439,452	$ 7,439,452	$ 9,299	$ 1,000,000	$ 1,250	$ 10,549	
21	$ 150,000,000	$ 32,986,301	$ 6,000,000	$ 26,986,301	$ 1,199,452	$ 7,199,452	$ 8,999	$ 1,000,000	$ 1,250	$ 10,249	
22	$ 150,000,000	$ 26,986,301	$ 6,000,000	$ 20,986,301	$ 959,452	$ 6,959,452	$ 8,699	$ 1,000,000	$ 1,250	$ 9,949	
23	$ 150,000,000	$ 20,986,301	$ 6,000,000	$ 14,986,301	$ 719,452	$ 6,719,452	$ 8,399	$ 1,000,000	$ 1,250	$ 9,649	
24	$ 150,000,000	$ 14,986,301	$ 6,000,000	$ 8,986,301	$ 479,452	$ 6,479,452	$ 8,099	$ 1,000,000	$ 1,250	$ 9,349	
25	$ 150,000,000	$ 8,986,301	$ 6,000,000	$ 2,986,301	$ 239,452	$ 6,239,452	$ 7,799	$ 1,000,000	$ 1,250	$ 9,049	
26	$ 150,000,000	$ 2,986,301	$ 6,000,000	$ -							

150,000,000-100,000,000=50,000,000 is treated as a capital addition and added to IC for the next year

Both Depreciation and Return on Capital for the first year are pro-rated by 275/365 as the asset is commissioned on April 1

Initial Capital in the year 2 is equal to the End Capital in the year 1 plus the capital addition made in the year 1

6) Transition rule for depreciation

For existing assets (i.e. assets commissioned before January 1, 2011), the original depreciation schedule will remain in place until a capital addition is made. At that time, **the annual depreciation amount will be re-calculated as 4% of the new CCC,** with zero salvage value as the default. For assets where the CCC cannot be determined, the depreciation amount in the current schedule, multiplied by an appropriate factor (i.e. 4/5 where the asset was being depreciated over 20 years at 5%/year), will be added to 4% of the new capital addition amount, with this sum being the new annual depreciation amount. A capital retirement will NOT trigger conversion to the new (25 year, 4% of CCC) depreciation schedule.

Example 2: An asset with an original cost of $100 million, and an annual capacity of 1000 units, has been depreciated at a rate of 5% from the beginning. In year 15 (after January 1, 2011), a capital addition of $35 million is made. This represents 35% of the existing CCC: as this proportion is greater than 10%, it is treated as a capital addition. The new annual depreciation amount is calculated as 4% of the new CCC, or 4% x (100 + 35) = $5.4 million per year. The new capital is effectively depreciated over 11.1 years, while the initial capital is effectively depreciated over an extended depreciation period of 26.1 years. **Figure 2** illustrates this example.

Figure 2

ORIGINAL DEPRECIATION SCHEDULE | NEW DEPRECIATION SCHEDULE AFTER CAPITAL ADDITION

Year	Cumulative Capital Cost	Initial Capital	Straight Line Dep'n (=5%*CCC)	End Capital	Return on Capital (4%)	Annual Capital Charge	Annual Capital Charge per unit	Annual Operating Charge	Annual Operating Charge per Unit	Annual COS per unit	Capital Addition	Initial Capital	Straight Line Dep'n	End Capital	Return on Capital (4%)	Annual Capital Charge	Annual Capital Charge per unit	Annual Operating Costs	Annual Operating Charge per Unit	Annual COS per unit
1	$ 100,000,000	$ 100,000,000	$ 5,000,000	$ 95,000,000	3,900,000.00	8,900,000	11,125	1,000,000.00	1,250	**12,375**										
2	$ 100,000,000	$ 95,000,000	$ 5,000,000	$ 90,000,000	3,700,000.00	8,700,000	10,875	1,000,000.00	1,250	**12,125**										
3	$ 100,000,000	$ 90,000,000	$ 5,000,000	$ 85,000,000	3,500,000.00	8,500,000	10,625	1,000,000.00	1,250	**11,875**										
4	$ 100,000,000	$ 85,000,000	$ 5,000,000	$ 80,000,000	3,300,000.00	8,300,000	10,375	1,000,000.00	1,250	**11,625**										
5	$ 100,000,000	$ 80,000,000	$ 5,000,000	$ 75,000,000	3,100,000.00	8,100,000	10,125	1,000,000.00	1,250	**11,375**										
6	$ 100,000,000	$ 75,000,000	$ 5,000,000	$ 70,000,000	2,900,000.00	7,900,000	9,875	1,000,000.00	1,250	**11,125**										
7	$ 100,000,000	$ 70,000,000	$ 5,000,000	$ 65,000,000	2,700,000.00	7,700,000	9,625	1,000,000.00	1,250	**10,875**										
8	$ 100,000,000	$ 65,000,000	$ 5,000,000	$ 60,000,000	2,500,000.00	7,500,000	9,375	1,000,000.00	1,250	**10,625**										
9	$ 100,000,000	$ 60,000,000	$ 5,000,000	$ 55,000,000	2,300,000.00	7,300,000	9,125	1,000,000.00	1,250	**10,375**										
10	$ 100,000,000	$ 55,000,000	$ 5,000,000	$ 50,000,000	2,100,000.00	7,100,000	8,875	1,000,000.00	1,250	**10,125**										
11	$ 100,000,000	$ 50,000,000	$ 5,000,000	$ 45,000,000	1,900,000.00	6,900,000	8,625	1,000,000.00	1,250	**9,875**										
12	$ 100,000,000	$ 45,000,000	$ 5,000,000	$ 40,000,000	1,700,000.00	6,700,000	8,375	1,000,000.00	1,250	**9,625**										
13	$ 100,000,000	$ 40,000,000	$ 5,000,000	$ 35,000,000	1,500,000.00	6,500,000	8,125	1,000,000.00	1,250	**9,375**		Initial Capital= (25M+35M)	New Depreciation = 4%* (100M+35M)	Remaining Useful Life = 11.1						
14	$ 100,000,000	$ 35,000,000	$ 5,000,000	$ 30,000,000	1,300,000.00	6,300,000	7,875	1,000,000.00	1,250	**9,125**										
15	$ 100,000,000	$ 30,000,000	$ 5,000,000	$ 25,000,000	1,100,000.00	6,100,000	7,625	1,000,000.00	1,250	**8,875**	$ 35,000,000									
16	$ 135,000,000											$ 60,000,000	$ 5,400,000	$ 54,600,000	2,292,000	7,692,000.00	9,615	1,000,000	1,250	**10,865**
17	$ 135,000,000											$ 54,600,000	$ 5,400,000	$ 49,200,000	2,076,000	7,476,000.00	9,345	1,000,000	1,250	**10,595**
18	$ 135,000,000											$ 49,200,000	$ 5,400,000	$ 43,800,000	1,860,000	7,260,000.00	9,075	1,000,000	1,250	**10,325**
19	$ 135,000,000											$ 43,800,000	$ 5,400,000	$ 38,400,000	1,644,000	7,044,000.00	8,805	1,000,000	1,250	**10,055**
20	$ 135,000,000											$ 38,400,000	$ 5,400,000	$ 33,000,000	1,428,000	6,828,000.00	8,535	1,000,000	1,250	**9,785**
21	$ 135,000,000											$ 33,000,000	$ 5,400,000	$ 27,600,000	1,212,000	6,612,000.00	8,265	1,000,000	1,250	**9,515**
22	$ 135,000,000											$ 27,600,000	$ 5,400,000	$ 22,200,000	996,000	6,396,000.00	7,995	1,000,000	1,250	**9,245**
23	$ 135,000,000											$ 22,200,000	$ 5,400,000	$ 16,800,000	780,000	6,180,000.00	7,725	1,000,000	1,250	**8,975**
24	$ 135,000,000											$ 16,800,000	$ 5,400,000	$ 11,400,000	564,000	5,964,000.00	7,455	1,000,000	1,250	**8,705**
25	$ 135,000,000											$ 11,400,000	$ 5,400,000	$ 6,000,000	348,000	5,748,000.00	7,185	1,000,000	1,250	**8,435**
26	$ 135,000,000											$ 6,000,000	$ 5,400,000	$ 600,000	132,000	5,532,000.00	6,915	1,000,000	1,250	**8,165**
27	$ 135,000,000											$ 600,000	$ 5,400,000	$ -						

A capital addition is added in the year 15 and deemed to occur at the beginning of the next year

7) Capital addition and retirement rules.

When a capital addition or a capital retirement is made, the addition or retirement will be deemed to occur at the beginning of the next calendar year. The initial value of the addition or the retirement is added to or subtracted from CCC for the purposes of calculating depreciation and applying the 10% capital/operating cost test for capital additions. The initial value of a capital addition is added to the next year's Initial Capital for calculating the ROC amount. The net book value (i.e. the depreciated value) of a capital retirement is subtracted from the next year's Initial Capital for the same purpose. **Example 3:** *A capital addition is made in the year 7 and a capital retirement is made in the year 15.* ***Figure 3*** *illustrates this example.*

Figure 3

Year	Cumulative Capital Cost	Initial Capital	Straight Line Dep'n	End Capital	Return on Capital (4%)	Annual Capital Charge	Annual Capital Charge per unit	Annual Operating Charge	Annual Operating Charge per Unit	Annual COS per unit	Capital Addition
1	$ 100,000,000	$100,000,000	$ 4,000,000	$ 96,000,000	3,920,000	7,920,000	9,900	1,000,000.00	1,250	**11,150**	
2	$ 100,000,000	$ 96,000,000	$ 4,000,000	$ 92,000,000	3,760,000	7,760,000	9,700	1,000,000.00	1,250	**10,950**	
3	$ 100,000,000	$ 92,000,000	$ 4,000,000	$ 88,000,000	3,600,000	7,600,000	9,500	1,000,000.00	1,250	**10,750**	
4	$ 100,000,000	$ 88,000,000	$ 4,000,000	$ 84,000,000	3,440,000	7,440,000	9,300	1,000,000.00	1,250	**10,550**	
5	$ 100,000,000	$ 84,000,000	$ 4,000,000	$ 80,000,000	3,280,000	7,280,000	9,100	1,000,000.00	1,250	**10,350**	
6	$ 100,000,000	$ 80,000,000	$ 4,000,000	$ 76,000,000	3,120,000	7,120,000	8,900	1,000,000.00	1,250	**10,150**	
7	$ 100,000,000	$ 76,000,000	$ 4,000,000	$ 72,000,000	2,960,000	6,960,000	8,700	1,000,000.00	1,250	**9,950**	$ 25,000,000
8	$ 125,000,000	$ 97,000,000	$ 5,000,000	$ 92,000,000	3,780,000	8,780,000	10,975	1,000,000.00	1,250	**12,225**	
9	$ 125,000,000	$ 92,000,000	$ 5,000,000	$ 87,000,000	3,580,000	8,580,000	10,725	1,000,000.00	1,250	**11,975**	
10	$ 125,000,000	$ 87,000,000	$ 5,000,000	$ 82,000,000	3,380,000	8,380,000	10,475	1,000,000.00	1,250	**11,725**	
11	$ 125,000,000	$ 82,000,000	$ 5,000,000	$ 77,000,000	3,180,000	8,180,000	10,225	1,000,000.00	1,250	**11,475**	
12	$ 125,000,000	$ 77,000,000	$ 5,000,000	$ 72,000,000	2,980,000	7,980,000	9,975	1,000,000.00	1,250	**11,225**	
13	$ 125,000,000	$ 72,000,000	$ 5,000,000	$ 67,000,000	2,780,000	7,780,000	9,725	1,000,000.00	1,250	**10,975**	
14	$ 125,000,000	$ 67,000,000	$ 5,000,000	$ 62,000,000	2,580,000	7,580,000	9,475	1,000,000.00	1,250	**10,725**	
15	$ 125,000,000	$ 62,000,000	$ 5,000,000	$ 57,000,000	2,380,000	7,380,000	9,225	1,000,000.00	1,250	**10,475**	-$ 15,000,000
16	$ 110,000,000	$ 51,000,000	$ 4,400,000	$ 46,600,000	1,952,000	6,352,000	7,940	1,000,000.00	1,250	**9,190**	
17	$ 110,000,000	$ 46,600,000	$ 4,400,000	$ 42,200,000	1,776,000	6,176,000	7,720	1,000,000.00	1,250	**8,970**	-$ 6,000,000
18	$ 110,000,000	$ 42,200,000	$ 4,400,000	$ 37,800,000	1,600,000	6,000,000	7,500	1,000,000.00	1,250	**8,750**	
19	$ 110,000,000	$ 37,800,000	$ 4,400,000	$ 33,400,000	1,424,000	5,824,000	7,280	1,000,000.00	1,250	**8,530**	
20	$ 110,000,000	$ 33,400,000	$ 4,400,000	$ 29,000,000	1,248,000	5,648,000	7,060	1,000,000.00	1,250	**8,310**	
21	$ 110,000,000	$ 29,000,000	$ 4,400,000	$ 24,600,000	1,072,000	5,472,000	6,840	1,000,000.00	1,250	**8,090**	
22	$ 110,000,000	$ 24,600,000	$ 4,400,000	$ 20,200,000	896,000	5,296,000	6,620	1,000,000.00	1,250	**7,870**	
23	$ 110,000,000	$ 20,200,000	$ 4,400,000	$ 15,800,000	720,000	5,120,000	6,400	1,000,000.00	1,250	**7,650**	

A capital addition is added in the year 7 and deemed to occur at the beginning of the next year

Initial value of the addition is added to IC

Initial value of the addition is added to CCC

A capital retirement is made in the year 15 and deemed to occur at the beginning of the nest year

Net book value of the retirement - ($15000000 - $9000000) = **$6000000**

==>15000000 x 15 yrs x 4% = $9000000

Net book value of the reitrement is subtracted from IC

Initial value of the retirement is subtracted from CCC

COS for Previously Partially Included Assets

Since January, 2009, only specific assets (or engineering systems) have been allowed to be partially included in a royalty Project. Some Projects with approvals dating from before 2009 include “previously partially included” assets which are now considered to be “measurable use” assets and not eligible for partial inclusion in a Project.

Rather than removing those previously approved assets from the Project descriptions, under the new COS rules the Department will use two COS calculations to “true up” the actual allowed costs (or ONP) accruing to the royalty Project from those assets.

Note that under the new COS rules, the allocation of an asset’s operating costs to a Project will always be determined by the proportion of actual use for the Project of the asset, not on the proportion of the asset originally included in the Project.

With respect to the capital component of the COS calculation, the two required calculations will be:

A. An annual Capital Recapture Amount, resulting in ONP or extra allowed costs to the royalty Project
B. A regular COS Schedule for any new eligible capital and operating costs incurred by the asset after the effective date of the new allocation business rules

1) Annual Capital Recapture Calculation

A recapture calculation will be necessary for previously partially included assets where the Project use percentage is different from the percentage of the capital cost of the asset originally included in the royalty Project. A schedule will be created to determine an annual capital charge based on the original capital cost of the asset at the time the new allocation rules come into effect.

This capital charge schedule will be calculated (starting from the effective date of the new cost allocation rules) for 25 years based on the original capital amount of the partially included asset. Each year the calculated capital charge will be multiplied by a percentage defined as (Original Capital Inclusion % - Annual Project Use %). The resulting amount will be an allowed cost of the Project in the year (if negative) or ONP of the Project in the year (if positive).

Example 4: A $100 million asset, with a design capacity of 1000 units per year and 800 units of throughput, was deemed to be 70% included in the royalty Project in 2004. In 2010 it is a measured use asset and its use in the Project is not always equal to 70%. **Figure 4** illustrates the capital charge schedule created for this asset. In the schedule, the negative (red) numbers represent extra allowed costs for the Project in a year, and the positive (black) numbers represent ONP attributed to the Project in a year.

Figure 4

RECAPTURE CALCULATION FOR 2004 PARTIALLY INCLUDED ASSETS

	Initial Capital	Depreciation	End Capital	Return on Capital (4%)	Annual Capital Charge	% Used by Royalty Project	(70% - New % Use) * Capital Charge Recapture Amount
2004						70%	
2005						70%	
2006						70%	
2007						70%	
2008						70%	
2009						70%	
2010	100,000,000	4,000,000	96,000,000	3,920,000	7,920,000	60%	792,000
2011	96,000,000	4,000,000	92,000,000	3,760,000	7,760,000	65%	388,000
2012	92,000,000	4,000,000	88,000,000	3,600,000	7,600,000	80%	760,000
2013	88,000,000	4,000,000	84,000,000	3,440,000	7,440,000	70%	0
2014	84,000,000	4,000,000	80,000,000	3,280,000	7,280,000	78%	582,400
2015	80,000,000	4,000,000	76,000,000	3,120,000	7,120,000	69%	71,200
2016	76,000,000	4,000,000	72,000,000	2,960,000	6,960,000	65%	348,000
2017	72,000,000	4,000,000	68,000,000	2,800,000	6,800,000	64%	408,000
2018	68,000,000	4,000,000	64,000,000	2,640,000	6,640,000	71% -	66,400
2019	64,000,000	4,000,000	60,000,000	2,480,000	6,480,000	70%	0
2020	60,000,000	4,000,000	56,000,000	2,320,000	6,320,000	70%	0
2021	56,000,000	4,000,000	52,000,000	2,160,000	6,160,000	70%	0
2022	52,000,000	4,000,000	48,000,000	2,000,000	6,000,000	74%	240,000
2023	48,000,000	4,000,000	44,000,000	1,840,000	5,840,000	69%	58,400
2024	44,000,000	4,000,000	40,000,000	1,680,000	5,680,000	72%	113,600
2025	40,000,000	4,000,000	36,000,000	1,520,000	5,520,000	68%	110,400
2026	36,000,000	4,000,000	32,000,000	1,360,000	5,360,000	60%	536,000
2027	32,000,000	4,000,000	28,000,000	1,200,000	5,200,000	65%	260,000
2028	28,000,000	4,000,000	24,000,000	1,040,000	5,040,000	67%	151,200
2029	24,000,000	4,000,000	20,000,000	880,000	4,880,000	70%	0
2030	20,000,000	4,000,000	16,000,000	720,000	4,720,000	68%	94,400
2031	16,000,000	4,000,000	12,000,000	560,000	4,560,000	75%	228,000
2032	12,000,000	4,000,000	8,000,000	400,000	4,400,000	50%	880,000
2033	8,000,000	4,000,000	4,000,000	240,000	4,240,000	58%	508,800
2034	4,000,000	4,000,000	-	80,000	4,080,000	70%	0
2035	-			-	-		
2036							
2037							
2038							
2039							
2040							
2041							
2042							
2043							
2044							

2) COS for Capital Additions to Previously Partially included Assets

In determining whether additions to previously partially included assets are treated as capital additions or operating costs, the CCC test is used. Expenditures in excess of 10% of the CCC will be treated as capital additions.

In applying this test to partially included assets, the CCC will be calculated as the original capital amount of the asset (not just the included portion) plus any capital additions made and less any capital retirements made.

When a capital addition is made to a previously partially included asset – i.e. a capital cost is incurred after the effective date of the new allocation and COS rules - depreciation on the asset for COS purposes will be calculated as 4% of the portion of ***the CCC incurred after the effective date of the new rules. Depreciation will only be calculated on the new capital which has been spent on the asset. Similarly, ROC is only computed on the new capital amount.***

Example 5: A $100 million asset, with a design capacity of 1000 units and 800 units of annual throughput was deemed to be 70% included in the royalty Project in 2004. In 2010, the asset is a measured use asset. Allowed costs for the Project are based on its actual Project use proportion. Since no capital costs are incurred until 2012, the COS calculation consists of only these operating charges for 2010 - 2012. When an investment of $50 million is made in 2012, it is treated as a capital addition (capital cost) because this amount is greater than 10% of the asset's $100 million CCC. The annual depreciation amount is calculated as 4% of the "new" CCC, which in this case would be $50 million. The $50 million also shows up as initial capital (IC) for 2013 and enters into the ROC calculation.

From 2013, the COS per unit charge for the asset in each year is the sum of the per unit operating charge and the per unit capital charge (based on the "new" capital amount). This charge, multiplied by the number of units used by the Project, is an allowed cost of the Project in each year. (Don't forget that the annual capital recapture amount [Figure 4] is also an allowed cost or ONP of the Project in each year.) **Figure 5** illustrates this example.

Figure 5

COS FOR NEW CAPITAL ADDITIONS AFTER 2010

	CCC for Depreciation	Capital Addition	Initial Capital	Depreciation	End Capital	Return on Capital (4%)	Annual Capital Charge	Annual Capital Charge per Unit	Annual Operating Costs	Annual Operating Charge per Unit	Annual COS per Unit	% of Asset Used by Royalty Project	Units Used by Royalty Project	Annual Allowed Cost to Royalty Project
2004												70%		
2005												70%		
2006												70%		
2007												70%		
2008												70%		
2009												70%		
2010	-								1,000,000	1,250	1,250	60%	480	600,000
2011	-								1,000,000	1,250	1,250	65%	520	650,000
2012	-								1,000,000	1,250	1,250	72%	576	720,000
2013	50,000,000	50,000,000	**50,000,000**	2,000,000	48,000,000	1,960,000	3,960,000	4,950	1,000,000	1,250	6,200	70%	560	3,472,000
2014	50,000,000		48,000,000	2,000,000	46,000,000	1,880,000	3,880,000	4,850	1,000,000	1,250	6,100	78%	624	3,806,400
2015	50,000,000		46,000,000	2,000,000	44,000,000	1,800,000	3,800,000	4,750	1,000,000	1,250	6,000	69%	552	3,312,000
2016	50,000,000		44,000,000	2,000,000	42,000,000	1,720,000	3,720,000	4,650	1,000,000	1,250	5,900	65%	520	3,068,000
2017	50,000,000		42,000,000	2,000,000	40,000,000	1,640,000	3,640,000	4,550	1,000,000	1,250	5,800	64%	512	2,969,600
2018	50,000,000		40,000,000	2,000,000	38,000,000	1,560,000	3,560,000	4,450	1,000,000	1,250	5,700	71%	568	3,237,600
2019	50,000,000		38,000,000	2,000,000	36,000,000	1,480,000	3,480,000	4,350	1,000,000	1,250	5,600	75%	600	3,360,000
2020	50,000,000		36,000,000	2,000,000	34,000,000	1,400,000	3,400,000	4,250	1,000,000	1,250	5,500	61%	488	2,684,000
2021	50,000,000		34,000,000	2,000,000	32,000,000	1,320,000	3,320,000	4,150	1,000,000	1,250	5,400	68%	544	2,937,600
2022	50,000,000		32,000,000	2,000,000	30,000,000	1,240,000	3,240,000	4,050	1,000,000	1,250	5,300	74%	592	3,137,600
2023	50,000,000		30,000,000	2,000,000	28,000,000	1,160,000	3,160,000	3,950	1,000,000	1,250	5,200	76%	608	3,161,600
2024	50,000,000		28,000,000	2,000,000	26,000,000	1,080,000	3,080,000	3,850	1,000,000	1,250	5,100	78%	624	3,182,400
2025	50,000,000		26,000,000	2,000,000	24,000,000	1,000,000	3,000,000	3,750	1,000,000	1,250	5,000	77%	616	3,080,000
2026	150,000,000	100,000,000	**124,000,000**	6,000,000	118,000,000	4,840,000	10,840,000	13,550	1,000,000	1,250	14,800	79%	632	9,353,600
2027	150,000,000		118,000,000	6,000,000	112,000,000	4,600,000	10,600,000	13,250	1,000,000	1,250	14,500	80%	640	9,280,000
2028	150,000,000		112,000,000	6,000,000	106,000,000	4,360,000	10,360,000	12,950	1,000,000	1,250	14,200	75%	600	8,520,000
2029	150,000,000		106,000,000	6,000,000	100,000,000	4,120,000	10,120,000	12,650	1,000,000	1,250	13,900	70%	560	7,784,000
2030	150,000,000		100,000,000	6,000,000	94,000,000	3,880,000	9,880,000	12,350	1,000,000	1,250	13,600	68%	544	7,398,400
2031	150,000,000		94,000,000	6,000,000	88,000,000	3,640,000	9,640,000	12,050	1,000,000	1,250	13,300	62%	496	6,596,800
2032	150,000,000		88,000,000	6,000,000	82,000,000	3,400,000	9,400,000	11,750	1,000,000	1,250	13,000	50%	400	5,200,000
2033	150,000,000		82,000,000	6,000,000	76,000,000	3,160,000	9,160,000	11,450	1,000,000	1,250	12,700	40%	320	4,064,000
2034	150,000,000		76,000,000	6,000,000	70,000,000	2,920,000	8,920,000	11,150	1,000,000	1,250	12,400	20%	160	1,984,000
2035	150,000,000		70,000,000	6,000,000	64,000,000	2,680,000	8,680,000	10,850	1,000,000	1,250	12,100	35%	280	3,388,000
2036	150,000,000		64,000,000	6,000,000	58,000,000	2,440,000	8,440,000	10,550	1,000,000	1,250	11,800	50%	400	4,720,000
2037	150,000,000		58,000,000	6,000,000	52,000,000	2,200,000	8,200,000	10,250	1,000,000	1,250	11,500	60%	480	5,520,000
2038	150,000,000		52,000,000	6,000,000	46,000,000	1,960,000	7,960,000	9,950	1,000,000	1,250	11,200	70%	560	6,272,000
2039	150,000,000		46,000,000	6,000,000	40,000,000	1,720,000	7,720,000	9,650	1,000,000	1,250	10,900	72%	576	6,278,400
2040	150,000,000		40,000,000	6,000,000	34,000,000	1,480,000	7,480,000	9,350	1,000,000	1,250	10,600	65%	520	5,512,000
2041	150,000,000		34,000,000	6,000,000	28,000,000	1,240,000	7,240,000	9,050	1,000,000	1,250	10,300	73%	584	6,015,200
2042	150,000,000		28,000,000	6,000,000	22,000,000	1,000,000	7,000,000	8,750	1,000,000	1,250	10,000	75%	600	6,000,000
2043	150,000,000		22,000,000	6,000,000	16,000,000	760,000	6,760,000	8,450	1,000,000	1,250	9,700	74%	592	5,742,400
2044	150,000,000		16,000,000	6,000,000	10,000,000	520,000	6,520,000	8,150	1,000,000	1,250	9,400	70%	560	5,264,000

1) Assets currently subject to COS calculations

For assets which are currently subject to COS calculations, the depreciation schedule will not change until a new capital addition is made. At that time the annual depreciation amount will be recalculated to reflect the new rules.

2) Previously Partially Included Assets

For assets which were previously partially included in a royalty Project, and are now measured use assets, an annual capital recapture calculation and a COS calculation will be necessary. The capital charge in the COS calculation will only include “new” capital.

3) New COS Assets

All new assets requiring COS calculations to determine allowed costs or ONP for a royalty Project will be required to follow the new COS business rules.

Appendix K

Advance Ruling Or Discretionary Allowed Cost Request

This request for advanced ruling is being submitted for:

- ☐ **Discretionary Allowed Cost**
- ☐ **Business Arrangement**
- ☐ **Other: Please Specify** ____

Date of Application	
Project Identification	
Project Name	
Project Operator	
Company	
OSR number	
Contact information	
Name	
Title	
Mailing Address	
Telephone number:	
Fax number	
Email	

Cost ($)	
Estimated cost	
Date costs incurred	
Business Case	
Reason for request (If this is a business arrangement please explain)	

Explain how the cost is directly related to the project	

Explain why the cost should be allowed (include any analysis and interpretations of regulatory sections)	

Long term benefits as a result of the additional cost	
Provide a list of Supporting Documents (If any please attach)	

Discretionary Cost Ruling or Decision (For Oil Sands Policy Use Only)	
Discretionary Cost Allowed (YES or NO)	
Reason for Allowing or Disallowing the Cost	