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5.1 NATURAL GAS ROYALTY/TAX CALCULATION SUMMARY

OVERVIEW

Starting with gas produced in March 2006 the method for calculating royalty/tax on natural gas and its by-products was changed. Net royalty/tax payable on gas produced in March 2006 and after is calculated for each well event, except for gas produced from oil wells that are in Production Entities. This has simplified the calculation of gas royalties, particularly when marginal, ultra-marginal and low productivity royalty rate reductions apply.

For periods before March 2006, production from facilities was assigned to facility-based Reporting Entities for a producer in proportion to the producer’s interest. See section 3.1 for a description of facility-based Reporting Entities. The Royalty/Tax Share of the production and the royalty/tax payable was then calculated for each Reporting Entity. This method is still used for amendments to periods before March 2006.

The following section describes the calculation of royalty and tax payable for gas produced in March 2006 and after. The calculation for periods before March 2006 is described in section 5.10.

ROYALTY AND TAX CALCULATION

Starting with production in April 2001, the Government of BC has been invoicing producers for natural gas royalties. Producers are only required to provide volumes of marketable gas available for sale and by-product sales volumes and values. Starting with production in March 2006, this information is provided for each well event and Production Entity (PE) on Natural Gas and By-Product Producer Allocations Reports (BC-08). The ministry uses this data and other information to calculate natural gas royalty and freehold production tax for each well event and PE and sends two monthly invoices to each produce: one for gas produced from oil wells in PE’s and one for gas produced from all other well events. See section 7.1 for a detailed description of these invoices.

Calculation of the royalty or tax payable is done in the following 7 steps:

1. Royalty/tax rates are determined for each well event and PE using certain attributes of the well event, average sales prices (Reference Prices) and average daily rates of raw gas production for some well events.

2. Gross royalty/tax for the month is calculated for marketable gas produced from each well event and PE by multiplying the Reference Price times the volumes of marketable gas times the royalty/tax rate for the well event or PE.

3. Gross royalty/tax for the month is calculated for by-products produced from each well event and PE by multiplying the sales value times the royalty/tax rate for each by-product and totaling them for the well event or PE.
ROYALTY AND TAX CALCULATION cont’d

(4) A weighted average royalty/tax rate is calculated for each well event and PE by dividing the sum of the gross royalty/tax for marketable gas and by-products produced from the well event or PE by the sum of the marketable gas volume produced from the well event or PE times the Reference Price plus the sales value of all by-products produced from the well event or PE.

(5) Gross royalty/tax is reduced by a Producer Cost of Service (PCOS) allowance for the producers’ field costs for gathering, dehydration and compression of the royalty/tax share. The PCOS allowance is calculated for each well event and PE by multiplying the volume of raw gas produced from the well event or PE times the weighted average royalty rate for the well event or PE times the PCOS rate for the facility to which the well is connected or PE.

(6) The gross royalty on exempt volumes and credits available to deep well events and deep re-entry well events are calculated and deducted to get Net Royalty/Tax Payable. If the available deep well credit for a well event is greater than the gross marketable gas and by-product royalty less the PCOS allowance, net royalty payable is reduced to zero. The deep well bank for each eligible well is reduced by the amount deducted from royalties payable on production from deep well events in the well.

(7) Net Royalty/Tax Payable for a producer’s interests in all PE’s are added together in a separate invoice for PE’s. Net royalty/tax payable for a producer’s shares of production from all other well events are added together in an invoice for all other well events.

 Marketable Gas Volume by Well Event or PE

The marketable gas volume is the volume of marketable gas available for sale based on the volume of raw gas processed during the production month and raw gas that may be used as fuel. This may not be the same as actual volumes delivered to buyers.

Royalty and Tax Rates

The royalty/tax rate is calculated in accordance with section 6(1) of the Royalty Regulation. The applicable rate for gas is dependent upon:

- whether the gas is produced from Crown land or freehold land, whether the gas is classified as Conservation gas or Non-conservation gas,
- if it is Non-conservation gas from Crown land, whether the gas is Base 15, Base 12 or Base 9,
- the Reference Price when it exceeds the Select Price for Base 9 or Base 12 Non-conservation gas or when it exceeds $50 per thousand cubic metres for any other gas, and
- the average daily rate of raw gas production.

See Section 5.2 for the meaning of important terms and the formulae for calculating royalty and tax rates on marketable gas and by-products.
ROYALTY AND TAX CALCULATION cont’d

Reference Price

The Reference Price is used to calculate the gross royalty/tax for marketable gas. The Reference Price is the greater of the Producer Price and the Posted Minimum Price.

A Producer Price is determined monthly for each producer at each gas processing plant at which the producer has production for the month. Producer prices are calculated as follows:

• Producers are required to submit invoices for all their sales of marketable gas in a given month to the Ministry of Energy, Mines and Petroleum Resources.

• An average sales price for all plant outlet and downstream sales made by a producer is calculated at a common pricing point.

• The average price is then netted back to the outlet of each processing plant using transportation charges actually incurred by the producer.

• For gas that is processed through producer-owned plants, the Gas Cost Allowance (GCA) is deducted to get an average value at the inlet of the plant. See Sections 5.6 and 6.13 for a more detailed discussion of GCA. For gas that is processed through plants that are not owned by producers, i.e. custom processing plants, processing charges are deducted as invoiced.

• A weighted average of the resulting inlet values and prices for sales by the producer at the plant inlet is the Producer Price at that plant.

• If Duke Energy Inc. is the custom processor and the producer uses Duke Energy’s raw gas gathering system, the average plant inlet value is reduced by Duke Energy’s raw gas gathering charges. The Producer Price is a weighted average of the resulting value and the prices for sales by the producer at the inlet to the Duke Energy system.

Producer Price calculations are described in more detail in section 5.3.

The Ministry of Energy, Mines and Petroleum Resources calculates and publishes a Posted Minimum Price (PMP) each month for each processing plant. The PMP is used as a price floor in calculating the royalty/tax rate and gross royalty/tax for a well event or PE. See Section 5.4 for a complete description of how the PMP is calculated.

By-Product Sales Value

For natural gas by-products, the sales volume is the actual amount disposed of. Natural gas by-product sales volumes at the plant outlet should be allocated to each well event or PE in proportion to the liquid content of the gas stream. The Sales Value for natural gas by-products is,

(i) the consideration received or receivable by the producer for their disposition less actual approved costs for processing and transporting the by-products from the point of production to the point of sale, or

(ii) if there is no actual sales price or if the sales price is in the opinion of the Administrator less than fair market value, a deemed value.

See section 5.7 for more details on natural gas by-products.
ROYALTY AND TAX CALCULATION cont’d

Producer Cost of Service (PCOS) Allowance

The PCOS allowance is an allowance of such amounts to cover a producer’s cost of:

(a) field gathering, dehydration and compression of Non-conservation gas,
(b) conserving conservation gas, and
(c) processing natural gas in the field for use as fuel in the field.

The PCOS allowance is deducted from the Gross Royalty/Tax. This allowance is allocated to the Royalty/Tax Share using the Weighted Average Royalty/Tax Rate which is the proportion of Total Gross Royalty/Tax to total sales value.

All producers are eligible for a PCOS deduction. PCOS rates are established for each reporting facility and depend upon:

(a) the equipment that is in place and in use in the field,
(b) the average costs of field equipment as determined by annual engineering studies and
(c) the volume of raw gas that is produced from well events delivering to the reporting facility.

A PCOS deduction is calculated for each well event. The amount of the deduction is equal to the PCOS rate per $10^3 m^3$ of raw gas times the well event’s share of raw gas production times the Weighted Average Royalty/Tax Rate to get the PCOS allowance that may be deducted from the Total Gross Royalty/Tax for the well event. The PCOS Allowance may not exceed 95 per cent of the Total Gross Royalty/Tax.

Coalbed methane projects are also eligible for a PCOS allowance for producers’ costs of handling water. If the water handling allowance is greater than the royalty on production of gas from the project in a month, the difference may be carried forward for deduction in future months.

See Section 5.5 for a more detailed discussion of the PCOS allowance.

Determining the Royalty Exempt Value

In rare circumstances gas may be exempt from royalty. See Section 5.9 for a complete description of gas that is exempt from royalty.

Credits for Deep Gas Wells

To encourage greater exploration for and development of deep gas resources, deep gas royalty incentives were introduced on July 1, 2003. These are intended to encourage exploration for deep reserves of natural gas by offsetting the higher drilling costs. These incentives were introduced on July 1, 2003 and modified on December 1, 2003.
There are different incentives for three types of deep gas wells: Deep Discovery Wells, Deep Wells and Deep Re-entry Well Events. The Deep Discovery Well incentive is an exemption from payment of royalties. The Deep Well incentive is a deduction from royalties that is based on the depth and type of well. The Deep Re-entry incentive is also a deduction from royalties, which is based on well event depth and amount of incremental drilling that is done. Tables that correlate well depths to drilling costs have been developed to provide royalty and tax incentives that are related to higher drilling and completion costs.

A well can only qualify for one of the Deep Well or Deep Re-entry incentives. However, a well may qualify for the Deep Discovery Well and either the Deep Well or Deep Re-entry incentives. Producers are entitled to the incentive that is of the greater benefit. Since well events on Crown or freehold land are eligible, the benefits are available against both royalties and freehold production taxes.
5.2 GAS AND GAS BY-PRODUCTS ROYALTY/TAX RATES

BASIC RATES

The royalty/tax rate is calculated in accordance with section 6(1) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation (B.C. Reg. 495/92). The applicable rate for gas is dependent upon:

- whether it is produced from Crown land or freehold land
- whether it is classified as Conservation gas or Non-conservation gas,
- if it is Non-conservation gas from Crown land, whether it is Base 15, Base 12 or Base 9,
- its Reference Price, and
- the Select Price

“Crown land” is land where the Crown has retained ownership of underlying oil and natural gas. Production of oil and natural gas from Crown lands requires a lease under the Petroleum and Natural Gas Act.

“Freehold land” is land where the Crown has granted ownership of underlying oil and natural gas to a person. Production of oil and natural gas from freehold lands does not require a lease under the Petroleum and Natural Gas Act.

“Conservation Gas” is gas produced from an oil well where the marketable gas is conserved, but does not include gas from an oil well granted concurrent production status under section 97 of the Petroleum and Natural Gas Act.

“Non-conservation Gas” is gas other than Conservation Gas and is classified into Base 15, Base 12 and Base 9. These classifications are defined as follows.

**Base 15 / Freehold:** Non-conservation gas that is produced from well events in a well having a spud date before June 1, 1998, or is revenue sharing gas.

**Base 12:** Non-conservation gas, other than revenue sharing gas, produced from well events that are not Non-Conservation Gas, Base 15 or Non-Conservation Gas, Base 9.

**Base 9:** Non-conservation gas, other than revenue sharing gas, produced from well events
(a) for which the entire spacing area is
   (i) in a lease that was disposed of under section 71 of the Act after May 1998, or
   (ii) in a lease that was issued from a permit or license that was disposed of under section 71 of the Act after May 1998
(b) which have a completion date not more than 60 months after the disposition date of the lease in paragraph (a) (i) or the disposition date of the permit or license in paragraph (a) (ii), as the case may be

“Revenue Sharing Gas” means gas the royalties from which are to be shared under the terms of a revenue sharing agreement applicable to that gas.
BASIC RATES cont’d

“Reference Price” for a producer’s gas is the greater of:

(i) the Producer Price for the producer’s gas in the month, and
(ii) the Posted Minimum Price for the month in which it is available for disposition.

“Producer Price” is an average sales price for all of the gas sold by a producer netted back to the plant at which the marketable gas volume is available for sale. The Ministry of Energy and Mines calculates Producer Prices monthly for each producer at each plant based on each producer’s sales invoices and transportation and treatment costs (see section 5.3).

“Select Price” is a price set by Order of the Administrator for each calendar year. It is a mechanism by which the Reference Price at which the minimum royalty rate takes effect can be adjusted for inflation. It is currently $50 per 10³m³ until further notice.

The formulae for calculating the royalty and tax rates are as follows:

(1) For marketable gas and by-products produced from Crown land:

<table>
<thead>
<tr>
<th></th>
<th>(i) if RP ≤ 50,</th>
<th>R% = 8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conservation Gas:</td>
<td>(ii) if RP &gt; 50,</td>
<td>R% = ( \frac{400 + 15(RP - 50)}{RP} )</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-Conservation Gas, Base 15:</td>
<td>(i) if RP ≤ 50,</td>
<td>R% = 15</td>
</tr>
<tr>
<td></td>
<td>(ii) if RP &gt; 50,</td>
<td>R% = ( \frac{750 + 25(RP - 50)}{RP} )</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-Conservation Gas, Base 12:</td>
<td>(i) if RP ≤ SP,</td>
<td>R% = 12</td>
</tr>
<tr>
<td></td>
<td>(ii) if RP &gt; SP,</td>
<td>R% = ( \frac{12 \times SP + 40(RP - SP)}{RP} )</td>
</tr>
<tr>
<td></td>
<td>(iii) if RP/SP ≥ 28/13,</td>
<td>R% = 27</td>
</tr>
<tr>
<td>Non-Conservation Gas, Base 9:</td>
<td>(i) if RP ≤ SP,</td>
<td>R% = 9</td>
</tr>
<tr>
<td></td>
<td>(ii) if RP &gt; SP,</td>
<td>R% = ( \frac{9 \times SP + 40(RP - SP)}{RP} )</td>
</tr>
<tr>
<td></td>
<td>(iii) if RP/SP ≥ 31/13,</td>
<td>R% = 27</td>
</tr>
<tr>
<td>Natural Gas Liquids</td>
<td></td>
<td>R% = 20</td>
</tr>
<tr>
<td>Sulphur</td>
<td></td>
<td>R% = 16.667</td>
</tr>
</tbody>
</table>

where, RP is the Reference Price in $ per 10³m³, SP is the Select Price in $ per 10³m³ and R is the royalty rate as a percentage.
(2) For all marketable gas and by-products produced from freehold land:

<table>
<thead>
<tr>
<th>Type</th>
<th>Condition</th>
<th>Formula</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conservation Gas</td>
<td>(i) if ( RP \leq 50 )</td>
<td>( R% = 5 )</td>
</tr>
<tr>
<td></td>
<td>(ii) if ( RP &gt; 50 )</td>
<td>( R% = \frac{245 + 9(RP - 50)}{RP} )</td>
</tr>
<tr>
<td>Non-Conservation Gas</td>
<td>(i) if ( RP \leq 50 )</td>
<td>( R% = 9 )</td>
</tr>
<tr>
<td></td>
<td>(ii) if ( RP &gt; 50 )</td>
<td>( R% = \frac{460 + 15(RP - 50)}{RP} )</td>
</tr>
<tr>
<td>Natural Gas Liquids</td>
<td></td>
<td>( R% = 12.25 )</td>
</tr>
<tr>
<td>Sulphur</td>
<td></td>
<td>( R% = 10.25 )</td>
</tr>
</tbody>
</table>

where, \( RP \) is the Reference Price in $ per \( 10^3 \) m\(^3\), and \( R \) is the royalty rate as a percentage.

The following graph illustrates the royalty curves for gas:

**Marketable Gas Royalty/Tax Base Rates**

![Graph showing royalty curves for gas](image-url)
PRODUCTION RELATED REDUCTIONS IN BASE RATES

For certain types of gas well events, base royalty and tax rates are reduced by factors related to the average daily rate of production from the well event. The types of well events that qualify for production-related rate reductions are low productivity, coalbed methane, marginal and ultramarginal well events.

1. Definition of Low Productivity Well Events

A reduction in royalty shares for low productivity gas wells was introduced in 2001 to prevent the government’s royalty from causing gas wells to be shut in when they reached rates of production that are too low to cover their operating costs.

Low productivity wells are well events with average raw gas production less than 5000 m$^3$ per day during a month and are not marginal, ultra-marginal or coalbed methane well events. The royalty/tax reduction applies to all non-conservation gas, which is gas produced from gas well events or from oil well events that are part of an approved concurrent production scheme. The reduction applies to all Crown and freehold well events regardless of when they were drilled or completed. A well event means all completions in a well in the same zone.

The reduction does not apply to conservation gas, which is gas from oil wells that are not part of an approved concurrent production scheme.

2. Definition of Coalbed Methane Well Events

Special royalty provisions were introduced in March 2002 to encourage development of British Columbia’s reserves of coalbed methane. These included a reduction in the royalty rate that is dependent on the rate of production from a well event, additional Producer Cost of Service Allowance provisions (see section 5.5) and credits for each coalbed methane well drilled.

A coalbed methane well event is a well event that is part of a coalbed methane project. A coalbed methane project is one or more wells that have been approved as a scheme under section 100 (1) (a) or (b) of the Petroleum and Natural Gas Act and are capable of producing natural gas from a geological stratum or strata containing mainly coal. Projects requiring approval under section 100 (1)(a) of the Act include repressuring, recycling, pressure maintenance or any other enhanced recovery technique. Projects requiring approval under section 100 (1)(b) are experimental applications of oilfield technology.

A coalbed methane well event cannot also be a low productivity well event.
3. Definition of Marginal Well Events

A reduction in royalty shares for marginal gas wells was introduced on July 1, 2003 to encourage development of gas reserves that are marginally economic because of depth and flow rates (pressure and permeability). Whereas the low productivity reduction is intended to keep existing wells from being shut in, the marginal well reduction is intended to encourage decisions to drill new gas wells.

A well event qualifies for the marginal well royalty rate reduction if it meets the following criteria:

(a) The primary product is natural gas.
(b) It is not part of a coalbed methane project.
(c) The spud date of the well is after May 31, 1998, i.e. it is subject to Base 9 and 12 royalty rates, unless it is on land that is subject to a revenue sharing agreement with the Fort Nelson, Blueberry or Doig First Nations in which case it may be subject to the Base 15 royalty rate.
(d) The first month in which marketable gas is produced from the well event is after June 2003, or it was suspended as of June 30, 2003 and reactivated after June 2003.
(e) The average daily production of natural gas per metre of depth in the 12-month period that begins with the first month in which the well event produces marketable gas is less than 23. This is calculated using the following formula:

\[
\frac{(TP / TPH)}{MWD} \times 24
\]

TP = total production of natural gas from the well event in the 12 consecutive calendar months starting with the month in which marketable gas is first produced from the well event, or, in the case of a reactivated well event, the month in which marketable gas is first produced after reactivation.

TPH = the total number of hours of production during the months referred to in the meaning of TP.

MWD = the marginal well depth of the well event. This depends on the type of well, as follows.

(i) For a well event in a vertical well, MWD is the true vertical depth to the top of pay, which is the distance from the intersection of the well bore with the pay of the well event to the point directly above that intersection that is the same elevation as the kelly bushing used in drilling the well.

(ii) For a well event in a horizontal well, MWD is the total measured depth of the well event, which is the length of the well bores from the surface to the well event. Since all well events in the same geological zone are considered for royalty purposes to be one well event, if a horizontal well has more than one lateral extension to well events in same zone, MWD includes the length of all of the lateral extensions.
PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont’d

4. Definition of Ultra-marginal Well Events

A reduction in royalty shares for ultramarginal gas wells was introduced on March 1, 2006 to encourage development of shallow gas reserves with low rates of production. The new incentive is similar to existing incentives for marginal and low productivity gas wells which progressively reduce the royalty rate when the average daily rate of natural gas production is below prescribed amounts. The ultra-marginal rate reduction is more significant than the rate reduction for marginal wells because it takes effect at higher rates of production. However, the conditions for a well to qualify for the ultra-marginal reduction are more stringent.

Only one of the production-based royalty reductions (low productivity, marginal and ultramarginal) can be applied to the same well event. Wells that satisfy the qualifying criteria for both marginal and ultra-marginal reductions will be given ultra-marginal status.

A well event qualifies for the ultramarginal well royalty reduction if it meets the following criteria:

(a) Its primary product is natural gas, but it is not part of a coalbed methane project. The ultramarginal royalty reduction does not apply to conservation gas or non-conservation gas produced from an oil well event.

(b) The well event is in a well with a spud date after December 31, 2005, or it is a reactivated well event with a re-entry date after December 31, 2005 in a well with a spud date after May 1998.

(c) The well event is in a vertical well with an Ultra-marginal Well Depth that is less than 2,500 meters or in a horizontal well with a Ultra-marginal Well Depth that is less than 2,300 meters. This limits the ultra-marginal rate reduction to wells that do not qualify for a deep well credit.

(d) If the well event is in an exploratory wildcat well, its average daily rate of production per metre of depth in the 12 month period that begins with the first month in which it produces marketable gas is less than 17. If the well event is in an exploratory outpost well or a development well, its average daily rate of production per metre of depth in the 12-month period that begins with the first month in which it produces marketable gas is less than 11. The average daily rate of production per metre of depth is calculated using the following formula:

\[
\frac{(TP / TPH) \times 24}{UWD}
\]

TP = the total natural gas production from the well event in the 12 consecutive calendar months starting with the month in which marketable gas is first produced from the well event. In the case of a reactivated well event, the 12 consecutive calendar months start with the month in which marketable gas is first produced following reactivation.

TPH = the total number of hours during which the well event produced marketable gas over the 12-month test period.
PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont’d

UWD = the Ultra-marginal Well Depth of the well event. This depends on the type of well, as follows.

(i) For a well event in a vertical well, UWD is the true vertical depth to the top of pay. This is the distance between the well bore’s intersection with the pay of the well event to the point, directly above that intersection point, that is the same elevation as the Kelly bushing used in drilling that well.

(ii) For a well event in a horizontal well,

- if the total measured depth (TMD) less the measured depth to the top of pay (MDTP) is less than 1,000 meters, UWD = TMD
- if TMD less MDTP is equal to or greater than 1,000 meters, UWD = MDTP + 1,000 + ( TMD – ( MDTP + 1,000 ) ) / 2

For a well event in a horizontal well, TMD is the length of all of the vertically and horizontally oriented well bores that constitute the well event.

(e) The 12-month test period in which gas production is measured to determine whether a well event qualifies for ultra-marginal status must end after January 2007.

5. Royalty/Tax Rate Reduction Factors

The production related reduction factors reduce royalty/tax rates by the basic royalty/tax rate multiplied by the reduction factor. The basic royalty/tax rates are the rates prescribed in section 6(1) of the Royalty Regulation and described in the previous section of this Handbook. The reduction factors are as follows:

(a) for low productivity well events: \( \frac{(5,000 - \text{ADV})}{5,000}^2 \)
(b) for coalbed methane well events: \( \frac{(17,000 - \text{ADV})}{17,000}^2 \)
(c) marginal well events: \( \frac{(25,000 - \text{ADV})}{25,000}^2 \)
(d) ultra-marginal well events \( \frac{(60,000 - \text{ADV})}{60,000}^{1.5} \)

In these formulas, ADV = the average daily natural gas production volume from the well event during the month in cubic meters. It is calculated as follows,

\[
\text{ADV} = \frac{\text{TP}}{\text{TPH}} \times 24
\]

TP = total natural gas production from the well event during the month, as reported on Monthly Production Statements (BCS1).

TPH = the total measured and prorated number of hours during which the well event produced natural gas during the month, as reported on BCS1’S.

For low productivity well events, if ADV is greater than 5,000 m³, the reduction factor is zero. For coalbed methane well events, if ADV is greater than 17,000 m³, the reduction factor is zero. For marginal well events, if ADV is greater than 25,000 m³, the reduction factor is zero. For ultra-marginal well events, if ADV is greater than 60,000 m³, the reduction factor is zero.
PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont’d

The following graph illustrates how reduction factors for low productivity, coalbed methane and marginal well events increase as the rate of production declines below 5,000, 17,000, 25,000 and 60,000 m$^3$ per day, respectively.

6. **Royalty Rate Reductions**

The low productivity, coalbed methane, marginal and ultra-marginal royalty rate reductions that are related to the rate of production from individual well events result in royalty/tax rates that are unique to the well event.

The production related reduction factors reduce royalty/tax rates by the basic royalty/tax rate multiplied by the reduction factor, as follows:

\[
\text{Royalty/Tax Rate} = \text{Basic Rate} - \text{Basic Rate} \times \text{Reduction Factor}
\]

The following graph illustrates how the royalty rate for Base 9 and 12 well events that are low productivity, coalbed methane, marginal and ultra-marginal well events decrease as the rate of production declines below 5,000, 17,000, 25,000 and 60,000 m$^3$ per day, respectively.
PRODUCTION RELATED REDUCTIONS IN BASIC RATES cont’d

To realize the benefit of a royalty rate reduction, a producer must report the marketable gas volumes that were produced from the qualifying well event on the BC08 Marketable Gas and By-Product Producer Allocations Report. The monthly crown invoice will then calculate a royalty rate reduction for the qualifying well event and apply the reduction to the marketable gas volume reported on the BC08.

RECALCULATIONS FOR FIRST 12 MONTHS OF PRODUCTION

For every new and reactivated well event with an initial production month after June, 2003, the ministry will review the marginal well eligibility after the well event’s first 12 months of production. If the well event is eligible for the marginal well reduction, the ministry will notify each producer with an ownership interest in the well event that it is a marginal well event. The ministry will recalculate royalties for those months in which average daily production from the well event is less than 25,000 m³/day, and will issue revised invoices for the well event for those months.
RECALCULATIONS FOR FIRST 12 MONTHS OF PRODUCTION cont’d

For every new and reactivated well event with an initial production month after January, 2006, the ministry will review the ultra-marginal well eligibility after the well event’s first 12 months of production. If the well event is eligible for the ultra-marginal reduction, the ministry will notify each producer with an ownership interest in the well event that it is an ultra-marginal well event. The ministry will recalculate royalties for those months in which average daily production from the well event is less than 60,000 m$^3$/day, and will issue revised invoices for the well event for those months.
GAS ROYALTY AND TAX CALCULATIONS

5.3 GAS SALES CONTRACT SUMMARY AND PRICING FOR MARKETABLE GAS

OVERVIEW

Valuation of marketable gas for royalty and freehold production tax purposes is based on each producer's actual sales prices. Producers are required to provide the Ministry of Energy, Mines and Petroleum Resources with copies of sales invoices or, in some cases, average pool prices.

The Ministry may request copies of contracts and updates any time during the year. The Ministry anticipates that the following types of contracts or information will be routinely requested:

- non-arms length gas sales;
- contracts for large volumes of gas;
- third party processing contracts;
- contracts with complex or unusual pricing provisions; and
- summary of sales’ pricing formulas.

PRODUCER PRICES

The Petroleum and Natural Gas Royalty and Freehold Tax Regulation (the royalty regulation) was amended on February 1, 1998 to provide authority for the Administrator to set out the “rules” that will be applied in determining prices to be used for royalty determination. These rules are set out in Order of the Administrator, Order 2001-2 (see pages 5.3-6 to 5.3-7). The term now used in the regulation for these prices is “Producer Price”. The Producer Price is used as a basis for calculating Crown royalties.

The royalty regulation defines a “producer” as:

(a) "a holder of a location who markets or otherwise disposes of oil, natural gas or both, that has been produced by
   (i) the holder of the location, or
   (ii) a person authorized to do so by the holder of the location, and

(b) a person authorized by a holder of a location to produce and market or otherwise dispose of, on the holder’s behalf, oil, natural gas or both”.

For gas entering Duke Energy's Westcoast system, a producer will be identified as one of those companies appearing on Duke Energy’s Determination of Production report unless the production source operator, or producer, otherwise notifies the Ministry of Energy, Mines and Petroleum Resources in writing. For gas not entering the Westcoast system, a producer will be identified from information provided to the Ministry of Small Business and Revenue by plant operators.

Producer Prices will only be calculated for producers identified as above and royalties will be based upon these prices.
PRODUCER PRICES cont’d

For each producer, a volume weighted average sales price for all sales at or downstream of plant outlets will be calculated at a common pricing point (i.e. all sales, except inlet sales, are netted forward or back using producer specific transportation costs to get to the common pricing point). The common pricing point is equivalent to Duke Energy’s Station 2 or the inlet to TransCanada Pipeline. The price at the common pricing point is then netted back to the inlet of each plant at which the producer has production using producer and plant specific applicable transportation charges and processing fees (custom processing fees, or Gas Cost Allowances).

A weighted average of this “netback price” and the prices of any sales made by the producer at the inlet of the plant are blended to get the Producer Price.

Order of the Administrator 2001-2 also specifies the following rules:

(a) When gas is disposed of and there is no arm’s length sale (e.g. put into storage, intra-company sales or swapped), the price is deemed to be the net selling price of all other sales for the producer in the region in which the disposition takes place.

(b) Energy based prices will be converted to volumetric prices using the average heating value of a producer’s own gas at a plant; and,

(c) The value of fuel consumed in transportation without consideration is factored into the calculation of Producer Prices by including it in the volume delivered to a buyer when calculating the per unit sales price. Producers wishing to have fuel costs factored in must submit supporting documentation showing fuel volumes.

Producer Prices are determined monthly in the 2nd month after the gas is produced, when the actual sales information is available. On a monthly basis producers must submit to the Ministry of Energy, Mines and Petroleum Resources copies of all sales invoices showing actual sales volumes and values. For gas sold into a producer’s pool, the producer must submit a summary outlining all buyers from the pool, sales revenue (excluding marketing, administration and financial hedging transactions), sales volume, and transportation costs. Note that gas purchases are not included in the calculation of the Producer Prices. The sales information submitted by the producer will be used to verify the resale price and, in combination with cost of service information, determine the Producer Price.

Plant operators are a primary source of information used for calculating Producer Prices. Duke Energy provides the Ministry of Energy, Mines and Petroleum Resources with:

- a monthly summary of production by producer;
- a statement of deliveries;
- cost of service invoices.

Producers are therefore not required to submit this information to the Ministry of Energy, Mines and Petroleum Resources for gas processed at a Duke Energy plant. Producers invoiced by a party other than Duke for processing or transmission service must provide the Ministry of Energy, Mines and Petroleum Resources with the appropriate invoices (this includes Duke Energy Midstream’s processing invoices) to ensure that these costs are factored into the Producer Price calculation. Failure to submit this information will result in the costs not being deducted in the calculation of Producer Prices. The Ministry of Energy, Mines and Petroleum Resources may also request that producers submit third party processing contracts.
GAS ROYALTY AND TAX CALCULATIONS

PRODUCER PRICES cont’d

Producers are required to submit sales and cost of service invoices by the 11th of the 2nd month after the month in which gas is produced. Late invoices may result in a Producer Price not being issued in time to be used for the royalty estimate. Insufficient royalty estimates may be subject to interest charges.

Producers are notified of Producer Price calculations through a Producer Price report. A Summary of Sales report and, if applicable, a Cost of Service report is also provided to the producer. These two reports provide the details of sales revenue and costs used in the Producer Price report.

GAS ROYALTY PRODUCER PRICE EXAMPLE

This example (TABLE 1) outlines a scenario where a producer has production behind two Duke processing plants and multiple sales (Sales A to F) at various points off the Duke system.

Provision of Data
For Sales A to D the producer must submit copies of sales invoices. For Sale E, (Alberta Pool sales), the producer must submit a summary outlining all buyers in the pool, sales revenue (excluding marketing, administration and hedging transactions), sales volume and transportation costs.

Step 1 - Sales Prices (Order 2001-2, section A, B, C4, C5)
The producer has four arm’s length sales (Sales A to D), one non-arm’s length transaction (Sale E) and an injection into storage (Sale F) for a total disposition volume of 444,000 GJ. Because of gas purchases and differences between injections into and withdrawals from storage, the sales volume may not be equal to the production volume.

Per unit sales prices are determined at the title transfer points for Sales A to D using invoices provided by the producer. Sale E will be valued at the producer’s average Alberta sales price. Sale F is an injection into storage and will be valued at the producer’s average sales price at the common pricing point.

Step 2 - Cost of Service (Order 2001-2, section C7, C8)
In this example, eligible deductions are calculated using the Westcoast cost of service data as well as data for transportation costs on Trans Canada. Any invoices submitted by the producer for custom processing fees other than Duke’s or brokered Duke service would also be factored in. The costs are applied over total volumes moved on that service type to determine a $/GJ rate.

Step 3 - Weighted average price at a common pricing point (Order 2001-2, section C3)
Once the sales price has been determined, all sales, except inlet sales, are netted forward or back using actual transportation costs, to the common pricing point (equivalent to Station #2 or the inlet to TransCanada Pipelines). For example, Sale B at the outlet of Duke Plant #2, is netted forward to Station 2 using T-North charges of $0.09/GJ. Sale C at Sumas is netted back using T-South charges of $0.30/GJ. Once these prices are calculated for each sale a weighted average price for all sales is determined at the common pricing point ($3.43/GJ in this example). The average price of $3.43/GJ is the price used for valuing Sale F (storage gas).
GAS ROYALTY AND TAX CALCULATIONS

GAS ROYALTY PRODUCER PRICE EXAMPLE cont’d

Step 4 - Determine plant production and heating values
The producer’s plant production volumes and heating values are obtained directly from Duke’s Determination of Production report, or data provided by the operators of non-Duke plants, if applicable.

TABLE 1

Step 1. Determine Sales Price and Title Transfer Point (from Producer Invoices)

<table>
<thead>
<tr>
<th>Sale #</th>
<th>Title Transfer Point</th>
<th>Sale Volume (GJ)</th>
<th>Sale Value ($CDN)</th>
<th>Sale Price ($/GJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Inlet to Westcoast Plant #1</td>
<td>50,000</td>
<td>50,000.00</td>
<td>2.15</td>
</tr>
<tr>
<td>B</td>
<td>Outlet of Westcoast Plant #2</td>
<td>75,000</td>
<td>120,000.00</td>
<td>3.25</td>
</tr>
<tr>
<td>C</td>
<td>Sumas</td>
<td>100,000</td>
<td>170,000.00</td>
<td>4.00</td>
</tr>
<tr>
<td>D</td>
<td>Station #2</td>
<td>27,000</td>
<td>47,250.00</td>
<td>3.40</td>
</tr>
<tr>
<td>E</td>
<td>Alberta Pool</td>
<td>72,000</td>
<td>140,400.00</td>
<td>3.35</td>
</tr>
<tr>
<td>F</td>
<td>Storage-Westcoast #2 Plant</td>
<td>120,000</td>
<td>n/a</td>
<td>deemed price</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>TOTAL</strong></td>
<td><strong>444,000</strong></td>
<td></td>
</tr>
</tbody>
</table>

Step 2. Determine Costs (Westcoast, Custom Processing, Third Party Brokering)

<table>
<thead>
<tr>
<th>Plant</th>
<th>Service</th>
<th>Rate ($/GJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Westcoast Plant #1</td>
<td>Gathering and Processing</td>
<td>0.45</td>
</tr>
<tr>
<td>Westcoast Plant #2</td>
<td>Gathering and Processing</td>
<td>0.50</td>
</tr>
<tr>
<td>TNorth Long Haul (TNLH)</td>
<td>Transportation</td>
<td>0.09</td>
</tr>
<tr>
<td>TSouth (TS)</td>
<td>Transportation</td>
<td>0.30</td>
</tr>
<tr>
<td>Miscellaneous (MISC)</td>
<td>Transportation on NOVA</td>
<td>0.18</td>
</tr>
</tbody>
</table>

Step 3. Determine Average Price at Common Pricing Point (equivalent to Station #2/NOVA Inlet)

<table>
<thead>
<tr>
<th>Sale #</th>
<th>Title Transfer Point</th>
<th>Sale Volume (GJ)</th>
<th>Sale Price ($/GJ)</th>
<th>TNLH ($/GJ)</th>
<th>TS ($/GJ)</th>
<th>MISC ($/GJ)</th>
<th>Average Price ($/GJ)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Inlet to Westcoast Plant #1</td>
<td>50,000</td>
<td>2.15</td>
<td>n/a</td>
<td></td>
<td></td>
<td>3.34</td>
</tr>
<tr>
<td>B</td>
<td>Outlet of Westcoast Plant #2</td>
<td>75,000</td>
<td>3.25</td>
<td>0.09</td>
<td></td>
<td></td>
<td>3.40</td>
</tr>
<tr>
<td>C</td>
<td>Sumas</td>
<td>100,000</td>
<td>4.00</td>
<td>(0.30)</td>
<td></td>
<td></td>
<td>3.70</td>
</tr>
<tr>
<td>D</td>
<td>Station #2</td>
<td>27,000</td>
<td>3.40</td>
<td></td>
<td></td>
<td></td>
<td>3.40</td>
</tr>
<tr>
<td>E</td>
<td>Alberta Pool</td>
<td>72,000</td>
<td>3.35</td>
<td>(0.18)</td>
<td></td>
<td></td>
<td>3.17</td>
</tr>
<tr>
<td>F</td>
<td>Storage-Westcoast #2 Plant</td>
<td>120,000</td>
<td>n/a</td>
<td></td>
<td></td>
<td></td>
<td>n/a</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>TOTAL</strong></td>
<td><strong>444,000</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>$ 3.43/GJ</strong></td>
</tr>
</tbody>
</table>

Step 4. Determine Plant Production and Heating Values

<table>
<thead>
<tr>
<th>Plant</th>
<th>Production (GJ)</th>
<th>Heating Value (GJ/m3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Westcoast Plant #1</td>
<td>150,000</td>
<td>42.356</td>
</tr>
<tr>
<td>Westcoast Plant #2</td>
<td>275,000</td>
<td>38.765</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>425,000</strong></td>
<td></td>
</tr>
</tbody>
</table>
Step 5 - Determine ‘Producer Prices’

From the average price at the common pricing point for the producer ($3.43/GJ), actual transportation and gathering and processing charges ($0.09/GJ and $0.45/GJ, respectively, for Plant #1) are deducted, to provide an average inlet price for downstream sales for each plant at which the producer has production ($2.89 at Plant #1). If there are inlet sales, a weighted average of this price and the average inlet sale price ($2.15/GJ) results in an average plant inlet price ($2.64/GJ). The average inlet price is multiplied by the average heat content of the producer's gas at the plant (42.356 GJ/m$^3$ at Plant #1) to obtain the Producer Price ($111.82/10^3$ m$^3$). This price should be used for all gas reporting entities for this producer at Plant #1.
Production at Source #1
150,000 GJ/3541.4 m³

Inlet to Westcoast Gathering System

Westcoast Plant #1
Processing: $0.45/GJ

Sale A

Production at Source #2
275,000 GJ/7094.0 m³

Inlet to Westcoast Gathering System

Westcoast Plant #2
Processing: $0.50/GJ

Sale B

Station #2
TNLH: $0.09/GJ

Sale D

Storage Facility
TNSH: $0.01/GJ

Sale F

Alberta Border

Sale E

Sumas
TS: $0.30/GJ

Sale C
Pursuant to subsection 2(5) of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation and effective April 1, 2001, producer prices shall be calculated in accordance with the following rules:

A. **Level of Aggregation:**

1) On a monthly basis, a producer price shall be calculated for each producer at each natural gas processing plant or dry gas facility to which natural gas, produced in British Columbia and allocated to the producer, is delivered.

B. **Geographic Point of Valuation:**

1) For gas delivered to a Westcoast Energy Inc. natural gas processing plant, the producer price shall be determined at the point of entry into the Westcoast Energy Inc. system.

2) For gas delivered to a producer-owned natural gas processing plant, the producer price shall be determined at the inlet to the natural gas processing plant.

3) For gas that does not require processing, the producer price shall be determined at the inlet to the first residue gas transmission line to which the marketable gas is delivered.

4) For gas delivered to a natural gas processing plant other than a Westcoast Energy Inc. natural gas processing plant or a producer-owned natural gas processing plant, the producer price shall be determined at the inlet to the natural gas processing plant.

C. **Method of Valuation:**

1) Sales of natural gas when sold at arm’s length shall, for the purpose of determining producer prices, be valued using the actual consideration received or receivable for the volume of marketable gas delivered. The actual consideration received or receivable shall include any demand or reservation fees, but shall exclude any marketing or administration fees and any gains or losses associated with hedging transactions.

2) Producer prices shall be equal to the volume weighted average of:
   a) the net selling price of sales for the producer for which the title transfer point is downstream of the geographic point of valuation, and
   b) the average price of sales for the producer for which the title transfer point is at the geographic point of valuation.
3) The net selling price for a producer shall be equal to the consideration received or receivable for all arm’s length sales made by the producer for which the title transfer point is downstream of the geographic point of valuation, divided by the volume of such sales, less per unit costs incurred by the producer to move the gas to the title transfer point from the geographic point of valuation.

4) For the following dispositions of natural gas, the selling price shall be equal to the net selling price of all other sales for the producer in the region in which the disposition takes place.
   a) Sales of natural gas made on a non-arm’s length basis;
   b) Sales of natural gas produced in British Columbia, for which the title transfer point is outside of British Columbia unless, in the opinion of the administrator, the natural gas was not commingled with natural gas produced outside British Columbia;
   c) Natural gas that is injected into a storage facility prior to being sold;
   d) Natural gas that is deemed to be native gas produced from a storage facility pursuant to a royalty agreement relating to the deeming of native gas production from that facility;
   e) Natural gas that is swapped for consideration which consists in whole or in part of natural gas at a different geographic location from that of the title transfer point;
   f) Any other dispositions for which, in the opinion of the administrator, an arm’s length price cannot be reasonably determined.

5) If the price defined in 4) above cannot be calculated, or the volume of the natural gas for which these prices are to apply is, in aggregate, less than the volume of all other sales of British Columbia sourced natural gas for the producer, then, the selling price for that volume of natural gas shall be equal to 1.25 times the Posted Minimum Price for the plant as defined in section 1 of the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation.

6) Where fuel is supplied by the producer for the purposes of delivering marketable gas to the buyer, without consideration, the volume of fuel supplied shall be included in the volume delivered to determine the per unit sales price. Where consideration is received from the buyer for the fuel, both the consideration and volume of fuel shall be added to the consideration received or receivable and volume of marketable gas delivered in determining the per unit selling price.

7) To determine a producer’s net selling price for a plant, the following per unit costs may be deducted from the consideration received or receivable:
   a) contract carriers’ per unit charges for transportation of residue gas on a residue gas transmission system calculated for each service zone,
   b) arm’s length processing fees where the natural gas has been processed at a natural gas processing plant or a portion of a natural gas processing plant owned by an unrelated party who is not a producer of natural gas at the plant in which the gas is processed,
   c) the approved Gas Cost Allowance rate for a producer owned plant or producer owned sales line where the natural gas has been:
      (i) processed at a producer owned plant or a portion of a producer owned plant, and/or
      (ii) transported on a producer owned sales line,
   d) fees charged to the producer by Westcoast Energy Inc. for raw gas gathering where natural gas has been processed at a natural gas processing plant owned by Westcoast Energy.
8) The total cost of service shall be reduced by any cost recoveries relating to service for which eligible costs have been deducted.

D. General:

1) Individual sales prices and costs shall be calculated in Canadian dollars per gigajoule.

2) Producer prices shall be calculated in Canadian dollars per thousand cubic metres.

3) The following conversion factors or methods shall be used:

<table>
<thead>
<tr>
<th>Conversion</th>
<th>Factor/Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>$Canadian to $US</td>
<td>Monthly Average Bank of Canada Daily Noon Rate</td>
</tr>
<tr>
<td>ft³ to m³</td>
<td>1 ft³ = 0.02832784 m³ (at 101.325 kPa 15°C)</td>
</tr>
<tr>
<td>MMBtu to GJ</td>
<td>1 MMBtu = 1.055056 GJ</td>
</tr>
<tr>
<td>$/GJ to $/10³m³</td>
<td>$/GJ times average GJ/10³m³ for producer’s production at a natural gas processing plant for the month</td>
</tr>
</tbody>
</table>

4) Revisions to revenues, costs or volumes used to calculate a producer price for a month which are a result of retroactive adjustments to invoices may be rolled into the calculation of the producer price for a subsequent month, provided that the roll-in does not impact the producer price materially. Any excess amount may be carried forward and rolled into future months until the excess amount is fully allocated.

5) This order remains in effect until cancelled or amended by Order of the Administrator.

Original signed by

Ross Curtis
Royalty Administrator
Dated at Victoria, British Columbia
this 11th day of April, 2001
5.4 POSTED MINIMUM PRICE FOR MARKETABLE GAS

OVERVIEW

The Posted Minimum Price (PMP) at a gas processing plant sets a minimum value for Reference Prices that are used to calculate royalty on gas produced at the plant. If the Producer Price for a producer at a plant is less than the PMP for the plant, the PMP must be used for royalty purposes.

The PMP is equal to 80% of an estimated average sales price for gas produced during each month. On about the 20th day of the 2nd month after the production month, the Ministry of Energy, Mines and Petroleum Resources calculates and publishes PMP's for five groupings of plants.

PLANT GROUPINGS

Since Producer Prices are values at the inlet of processing plants, they will vary from plant to plant because of differences in transportation and processing costs. To make the PMP test sensitive to these differences, separate PMP's are calculated for 5 groups of plants. These plant groups were defined with considerations to plant size, gas quality and market access. Each processing plant is assigned to one of the groups by Order of the Administrator. As of August 2006, the plant groups were as follows.

<table>
<thead>
<tr>
<th>Plant Group</th>
<th>Plant Group Description</th>
<th>Facility Code</th>
</tr>
</thead>
<tbody>
<tr>
<td>Group 1</td>
<td>Fort Nelson</td>
<td>0437</td>
</tr>
<tr>
<td>Group 2</td>
<td>McMahon</td>
<td>0439</td>
</tr>
<tr>
<td>Group 3</td>
<td>Pine River</td>
<td>0442</td>
</tr>
<tr>
<td>Group 4</td>
<td>Plants Delivering Gas to the Duke Transportation System</td>
<td>Various</td>
</tr>
<tr>
<td>Group 5</td>
<td>Plants Delivering Gas to TransCanada &amp; Alliance Transportation Systems</td>
<td>Various</td>
</tr>
</tbody>
</table>
PMP CALCULATIONS

PMP values are 80% of estimated volume weighted average prices of all natural gas sales (domestic and export; spot, short-term and long-term, firm and interruptible) net of applicable gathering, processing, and transportation charges.

PMP values are calculated monthly using information provided by producers, aggregators, custom processors, pipeline companies, and independent publications. The Natural Gas Market Report, Inside FERC, and the Daily Oil Bulletin are examples of sources used for gas prices. Duke Energy provides cost of service data relating to the majority of gas gathered, processed and transported in the province. Several aggregators and distributors are contacted monthly to obtain current gas sales contract prices.

PMP EXEMPTIONS

The Order of the Administrator 98-3 designates certain wells as being PMP exempt. Prior to February 1, 1998, these wells received an exemption from PMP due to their high H₂S content. When the wells identified in the Order no longer produce, there will be no PMP exemptions.

USE OF THE PMP IN THE NATURAL GAS ROYALTY/TAX CALCULATION

The PMP is applied in both the determination of the royalty/tax rate and the valuation of the royalty/tax share of marketable gas. The PMP does not apply to by-products. See Section 5.1 for further details of the use of the PMP in the royalty calculation.

PUBLICATION OF THE POSTED MINIMUM PRICE

The five plant group PMP values are issued by approximately the middle of the month following the production month. Notification will be made to industry by the Ministry of Energy, Mines and Petroleum Resources via Information Letters, which are faxed to producers and are also available on the ministry website at: www.sbr.gov.bc.ca or www.gov.bc.ca/em/.
5.5 PRODUCER COST OF SERVICE ALLOWANCE

GENERAL DESCRIPTION

Producer Cost of Service (PCOS) is an allowance for the cost of moving the Royalty/Tax Share of raw gas from the wellhead to the inlet of a gas processing plant. The PCOS allowance is intended to cover the Crown’s share of costs for gathering, dehydration and compression of raw gas and in some cases processing gas that is used as fuel in these activities. It does not include processing costs for the gathered gas as these costs are included in either the Gas Cost Allowance for producer-owned plants or processing tolls at third party processing plants, which are deducted in the determination of the Producer Prices.

Prior to April 2005, PCOS rates were calculated for the following four categories:

1. Gathering and Dehydration
2. Compression
3. Field Processing
4. Conservation of Conservation Gas

Separate rates per 10^3 m^3 of raw gas were periodically set for each PCOS category at each gas processing plant except for Conservation of Conservation Gas, which received the same rate for all plants.

Effective April 2005, the methodology for calculating PCOS rates was changed. PCOS rates are now calculated on an annual basis in accordance with procedures established under the PCOS Order of the Administrator. PCOS rates are calculated for each reporting facility (rather than plant) producing Non-Conservation Gas. The PCOS rate for reporting facilities producing Conservation Gas remains at $16.00.
ORDER OF THE ADMINISTRATOR  2006-01
IN THE MATTER OF SECTION 2 (8.1) OF THE
PETROLEUM AND NATURAL GAS ROYALTY AND FREEHOLD
PRODUCTION TAX REGULATION

Order of the Administrator
Procedures For Establishing Producer Cost of Service Rates

Methodology for Calculating A Producer Cost of Service Allowance:

The Producer Cost of Service (PCOS) allowance is a deduction from natural gas royalties designed to compensate a producer for costs associated with gathering, dehydration and compression of natural gas before processing. A PCOS allowance is calculated for each producer’s share of raw gas production from each well event as defined in the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation.

The formula for calculating a PCOS allowance is as follows:

PCOS Natural Gas Volume  X  PCOS rate  X  Weighted Average Royalty Rate

where,

a) The PCOS Natural Gas Volume is equal to the producer’s share of raw gas production from the well event,
b) The PCOS Rate is a rate per thousand cubic meters of raw gas established by the Royalty Administrator for the reporting facility that handles natural gas produced from the well event, and
c) The Weighted Average Royalty Rate is the average royalty rate for all of the well event’s marketable gas and by-product volumes for the month.

PCOS Rate Calculation

A. There are two types of PCOS rates:

i) Conservation PCOS rate: The Conservation PCOS rate is equal to $16.00 and is assigned to all reporting facilities handling raw gas from well events producing conservation gas for sale.

ii) Non-Conservation PCOS rates: Non-Conservation PCOS rates are calculated for all reporting facilities handling raw gas from well events producing non-conservation gas for sale.
B. Timing for Calculation of Producer Cost of Service Rates:

Effective the production month of April, 2005, PCOS rates are to be calculated for each reporting facility that is producing marketable gas.

Effective the production month of January, 2006 and for each January production month thereafter, an annual PCOS rate will be calculated for each reporting facility producing marketable gas.

Note: Where a reporting facility begins producing marketable gas during a calendar year, a PCOS rate will be calculated effective the initial production month of the reporting facility.

C. PCOS rates are derived from the following information:

1. Reports from facility operators about equipment items (i.e. gathering lines, dehydrators, compressors, lineheaters and field processing units) at their reporting facilities,
2. Annual operating and capital cost curves provided by engineering consultants. Note that beginning with the 2005 calendar year, the Ministry of Energy, Mines and Petroleum Resources will obtain an annual update of the operating and capital cost curves to be used in PCOS rate calculations from an independent engineering consulting firm,
3. Raw gas production data from BCS1 Production Reports, BCS2 Monthly Disposition Reports and BC22 Producer Cost of Service applications,
4. Reporting facility and well data extracted from the Royalty Management System,
5. Annual inflation information from the Nelson Farrar Index, and
6. Ministry of Small Business and Revenue Field Inspection Reports.

D. A PCOS rate is based on the following cost factors:

1. Depreciation of equipment items (i.e. gathering lines, compressors, dehydrators, lineheaters and field processing units)
2. Operating costs, and
3. A 15% return on invested capital (Return on Rate Base)

E. There are seven steps involved in the calculation of a PCOS rate:

1. Update the Database for Equipment Items at each Reporting Facility,
2. Determine an Opening Capital Balance for Equipment Items at a Reporting Facility,
3. Determine Operating Costs for Equipment Items and Wells at each Reporting Facility,
4. Determine the Natural Gas Production Volume for each Reporting Facility
5. Calculate Depreciation, Operating Costs and a Return on Rate Base for each equipment item at a Reporting Facility,
6. Calculate a PCOS Rate for each Reporting Facility,
7. Calculate a Final PCOS Rate for each Reporting Facility.
Step 1 – Update the Database for Equipment Items at each Reporting Facility

Accurate calculation of PCOS rates requires knowledge of the equipment items at each reporting facility. Information about new installations are reported by industry on an ‘Application for Producer Cost of Service’ (BC22) report. Information about equipment that has been changed or retired is obtained from facility operators and through field inspection and audit activity. This information is kept in a database maintained by the Ministry of Small Business and Revenue to be used in the calculation of PCOS rates.

The types of equipment and the relevant attributes that are inventoried in the PCOS database are as follows:

**Gathering Lines**

Attributes:
1. Pipeline Length (kilometers)
2. Pipeline Diameter (millimeters)
3. Year installed

**Compressors**

Attributes:
1. Type (i.e. Turbine, Gas, Electric, Electric Screw, Gas Screw)
2. Horsepower
3. Year installed
4. Sweet or Sour Service

**Dehydrators**

Attributes:
1. Type (i.e. Glycol, Dessicant)
2. Capacity
3. Year Installed
4. Sweet or Sour Service for Glycol Dehydrators

**Field Processing Units**

Attributes:
1. Type (i.e. Amine, Iron Sponge, Molecular Sieve)
2. Acid gas content of the gas stream
3. Capacity
4. Year Installed

**Lineheaters**

Attributes:
1. Type (i.e. Single Pass, Double Pass)
2. Average Capacity
3. Sweet or Sour Service
4. Facility Effective Date
Wellsite Operating Costs
Attributes:
1. Number of producing wells
2. Sweet or Sour Service

Step 2 – Determine an Opening Capital Balance for Equipment Items at a Reporting Facility

For each reporting facility, an opening capital balance is determined using the following procedures:

i) Determine Original Cost for each equipment item. The procedures for determining Original Cost for an equipment item vary depending on the equipment item’s installation date.
   a) For equipment items installed before 1997, the equipment item will be valued using the 1996 Engineering Cost Curves, relevant equipment item attributes and the Nelson Farrar inflation index.
   b) For equipment items installed between 1997 and 2004, the equipment item will be valued using the 1999 Engineering Cost Curves, relevant equipment item attributes and the Nelson Farrar inflation index.
   c) For equipment installed after 2004, equipment items will be valued using the Engineering Cost Curves applicable to that installation year and the relevant equipment item attributes.

The formulas for determining Original Cost for each equipment item are listed below. Note that the Inflator/Deflator are only used to value equipment items with installation dates prior to 2005.

Gathering Lines:
Line Length × Line Diameter × Cost Factor Per Millimeter/Kilometer × Inflator/Deflator

Compressors:
Compressor Horsepower × Cost Factor Per Horsepower × Inflator/Deflator

Dehydrators:
Dehydrator Capacity × Cost Factor per Unit of Capacity × Inflator/Deflator

Field Processor Units:
Processor Capacity × Cost Factor per Unit of Capacity × Inflator/Deflator

Lineheaters:
Lineheater Capacity × Cost Factor per Unit of Capacity × Inflator/Deflator

Note: Lineheater capacity is equal to the facility’s production in mcf/d divided by the number of producing wells at the facility.
The following additional adjustments may be made in the Original Cost calculation to allow for more accurate matching of capital costs to production volumes:

a) Where there are compressors within producer-owned plants that are performing a field compression and sales compression function, the compressor’s original cost calculation will be reduced by a fixed percentage representing the sales compression portion of the compressor. This reduction to the compressor’s original cost is required to ensure that producers do not receive a duplicated GCA and PCOS deduction for the same compressor.

b) Where an equipment item is being shared by multiple British Columbia reporting facilities, the original cost calculation of the equipment item will be allocated to each reporting facility delivering to the equipment item. The original cost allocation will be based on production volumes for each reporting facility or a fixed percentage obtained from the operator of the reporting facility.

c) Where an equipment item is being used to handle raw gas volumes from British Columbia and another jurisdiction, the original cost calculation for the equipment item will be allocated between British Columbia and the other jurisdiction based upon a fixed percentage obtained from the facility operator.

ii) Determine an opening capital balance for each equipment item as follows:

a) For 2005 opening capital balance calculations:

i) equipment items with an installation year less than or equal to the reporting facility’s Previous PCOS Rate Approval Year, calculate the equipment item’s opening capital balance using Original Cost and 5% declining balance depreciation methodology. The formula for this calculation is as follows:

\[(\text{Original Cost} \times (0.95^{(2005-\text{Installation Year})}))\]

Note: Previous PCOS Rate Approval Year is equal to the calendar year that the reporting facility’s latest plant based PCOS rate was issued.

ii) equipment items with an installation year greater than 2004, calculate the equipment item’s opening capital balance using Original Cost and 20 year straight line depreciation methodology. The formula for this calculation is as follows:

\[\text{Original Cost} – (\text{Original Cost} / 20) \times A\]

Where:

A is equal to the lesser of 20 and the number obtained by deducting 2004 from the calculation year.

b) For opening capital balance calculations for calculation years subsequent to 2005:

i) equipment items with an installation year greater than 2005, calculate the equipment item’s opening capital balance using Original Cost and 20 year straight line depreciation methodology. The formula for this calculation is as follows:

\[\text{Original Cost} – (\text{Original Cost} / 20) \times A\]

Where:

A is equal to the lesser of 20 and the number obtained by deducting 2004 from the calculation year.

ii) equipment items with an installation year less than 2005, calculate the equipment item’s January 1, 2005 opening capital balance using the methodology under Step 2 (ii) (a) above
and then apply 20 year straight line depreciation for each year after 2004. The formula for this calculation is as follows:

\[ \text{OCB} - \left( \frac{\text{OCB}}{20} \right) \times A \]

Where:

- OCB is equal to the January 1, 2005 Opening Capital Balance calculated under Step 2 (ii) (a) above, and
- A is equal to the lesser of 20 and the number obtained by deducting 2004 from the calculation year.

### Step 3 – Determine Operating Costs for Equipment Items and Wells at Each Reporting Facility

For each reporting facility, determine the amount of annual operating costs for each equipment item and well assigned to the reporting facility using the following procedures:

a) For each equipment item, determine the operating cost percentage using the following formulas:

#### Gathering Lines:

\[ \text{Operating Cost \%} = 2.33 + \frac{(4.00 \times 4010.29)}{(4010.29 + \text{Length in Meters})} \]

#### Compressors:

\[ \text{Operating Cost \%} = 7.44 + \frac{(5.58 \times 450.27)}{(450.27 + \text{HP})}, \text{where HP is the horsepower of the compressor.} \]

#### Dehydrators:

i) **Glycol Dehydrators:** Operating Cost \% = \(7.12 + \frac{(9.41 \times \text{Capacity})}{(5.14 + \text{Capacity})}\), where Capacity is equal to the capacity in MMSCF/D of the dehydrator.

ii) **Dessicant Dehydrators:** Operating Cost \% = \(11.25 + \frac{(8.07 \times 5.14)}{(5.14 + \text{Capacity})}\), where Capacity is equal to the capacity in MMSCF/D of the dehydrator.

#### Lineheaters:

\[ \text{Operating Cost \%} = 6.25 + \frac{(18.82 \times 5.14)}{(5.14 + \text{M\_CAP\_H})} \text{ Where M\_CAP\_H is equal to the capacity in MMSCF/D of the lineheater.} \]

#### Field Processing Units:

a) Operating Cost \% = \(11.25 + \frac{(8.07 \times 5.14)}{(5.14 + \text{M\_CAP})}\), where M\_CAP is the capacity in MMSCF/D of the field processing unit.

b) For each equipment item, calculate an operating cost amount by multiplying the operating cost percentage by the opening capital balance for the calculation year.

c) Wellsite operating costs are calculated for each producing well as a fixed amount per producing well at each reporting facility. The operating cost amounts per well depend on the average H\(_2\)S content of the gas being processed at a reporting facility.
H₂S < 1%,  operating costs = $ 9,069.84 per well
H₂S ≥ 1%,  operating costs = $13,454.34 per well

d) For each reporting facility, sum the wellsite operating costs and the operating costs for each equipment item to determine the reporting facility’s total operating costs.

Step 4 – Calculate Depreciation and Return on Rate Base for each Reporting Facility

To calculate depreciation and return on rate base for a reporting facility, sum the opening capital balances for all equipment types and then apply the following formulas:

Depreciation = Opening Capital Balance / 20, (i.e. 20 Year Straight Line Depreciation)

Return on Rate Base = .15 x (( Opening Capital + Closing Capital)/2) + Working Capital Allowance)

Where,

i) Opening Capital is the sum of all opening capital balances for all equipment items associated with a reporting facility,

ii) Closing Capital is equal to Opening Capital less Depreciation calculated above, and

iii) Working Capital Allowance is equal to Operating Costs as per Step 3 above divided by six.

Step 5 – Determine the Volumetric Throughput for Each Reporting Facility

For the 2005 calculation year, the calculation of the volumetric throughput for each reporting facility is based on an estimate of the raw gas volume throughput for the reporting facility. This estimate will be based on either the previous year’s actual BCS2 production volumes or BC22 PCOS Application estimates.

For calculation years subsequent to 2005, the calculation of the volumetric throughput for each reporting facility will be equal to the sum of:

i) an estimate of the raw gas volume throughput for the reporting facility. This estimate will be based on either the previous year’s actual BCS2 production volumes or BC22 PCOS Application estimates obtained from facility operators, and

ii) an adjustment to actual for the previous year. The adjustment to actual will be equal to the reporting facility’s actual raw gas production volumes for the year prior to the calculation year less the reporting facility’s estimated raw gas production volume used in the previous year’s PCOS rate calculation. Where the adjustment to actual materially impacts the volumetric throughput calculation for the calculation year, the adjustment to actual will be revised to nil and the previous year’s PCOS rate will be recalculated based on the actual production volumes for the reporting facility.
Step 6 – Calculate a PCOS Rate for each Reporting Facility

Calculate a PCOS rate per thousand cubic meters of raw gas for each reporting facility. This is done by adding depreciation, operating costs and return on rate base amounts for the reporting facility and then dividing by the adjusted raw gas volume calculated under Step 5 above.

Step 7 – Calculate an Adjusted PCOS Rate for each Reporting Facility

The calculation of PCOS allowances on the Crown Invoice will be based on an Adjusted PCOS Rate. For each reporting facility in a calculation year, the Adjusted PCOS Rate will be equal to the product obtained by multiplying the PCOS rate calculated under Step 6 above by the applicable Revenue Neutral Factor outlined below:

<table>
<thead>
<tr>
<th>Calculation</th>
<th>Revenue Neutral Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year</td>
<td></td>
</tr>
<tr>
<td>2005</td>
<td>B / C</td>
</tr>
<tr>
<td>2006</td>
<td>B / C</td>
</tr>
<tr>
<td>2007</td>
<td>((C – B) x 1 / 3 + B) / C</td>
</tr>
<tr>
<td>2008</td>
<td>((C – B) x 2 / 3 + B) / C</td>
</tr>
<tr>
<td>2009 &amp; Subsequent Years</td>
<td>1.00</td>
</tr>
</tbody>
</table>

Where:

**B means the Provincial Base Annual PCOS Allowance**

For each calculation year from 2005 to 2008, the Provincial Base Annual PCOS Allowance is equal to the sum of the Base Annual PCOS Allowances for each reporting facility active in British Columbia. The calculation of the Base Annual PCOS Allowance for each reporting facility will be equal to the estimated volumes for each reporting facility using the procedures described in Step 5 above multiplied by the reporting facility’s applicable PCOS Rate approved by the Royalty Administrator as at March 31, 2005.

**C means the Provincial Calculated Annual PCOS Allowance**

For each calculation year from 2005 to 2008, the Provincial Calculated Annual PCOS Allowance is equal to the sum of the Calculated Annual PCOS Allowances for each reporting facility active in British Columbia. The Calculated Annual PCOS Allowance for each reporting facility will be equal to the estimated volumes for each reporting facility using the procedures described in Step 5 above multiplied by the reporting facility’s PCOS Rates determined under Step 6 above.

Dated at Victoria, British Columbia
this 12th day of April, 2006

David Moliński
Royalty Administrator
INDUSTRY INPUT

The primary mechanism for industry input is the BC-22 form “Application for Producer Cost of Service”. The Ministry encourages all facility operators to submit this form for new facilities or whenever changes are made to equipment at an existing facility. The submission of a BC-22 for a new reporting facility will trigger the calculation of a new PCOS rate. A BC-22 submission for an existing facility will not trigger a new PCOS rate recalculation but will be included in the next annual PCOS rate recalculation. Failure to submit the BC-22 form for equipment additions will result in the value of the equipment not being included in future rate calculations.

PCOS RATES

Up-to-date PCOS rates are available on the Ministry website at: www.gov.bc.ca/rev/.

X-REFERENCE

Refer to Section 6.10 for the BC-22 Completion Guidelines.
5.6 GAS COST ALLOWANCE

OVERVIEW

The Gas Cost Allowance (GCA) is a rate per \(10^3\) m\(^3\) of raw gas approved by the Royalty Administrator to offset the capital and operating costs associated with:

1. processing the Crown’s share of raw gas at a producer-owned gas plant, and

2. transmission of the Crown’s share of residue gas through a producer-owned sales line.

A producer-owned gas plant or sales line may be for a producer’s own use, or for the use of another producer who pays to use the plant. Producers who pay a custom-processing fee to process and/or transport their gas at a producer-owned plant will only receive the approved GCA rate for that calendar period for that plant.

GCA rates are deducted from average sales values in Producer Price calculations for marketable gas at producer-owned plants. (see Section 5.3 for further information). The approved GCA rates per \(10^3\) m\(^3\) of raw gas are converted to a rate per GJ of marketable gas at the average shrinkage rate and heat content for the plant.

The GCA rate flows from the application of the actual allowable capital and operating costs incurred at a processing plant against the volumes of gas processed through the plant.

ALLOWABLE EXPENDITURES

Allowable costs of a processing plant for a calendar year are the following:

1. **Allowable direct operating costs.**
   
   Allowable direct operating costs include an overhead allowance equal to 10% of total direct operating costs incurred during the year. Actual overhead and indirect charges are not allowed. See Schedule III in Section 6.11 for a list of allowable direct operating costs and Schedule IV in Section 6.11 for a list of expenses that are not allowable.

2. **A provision for depreciation of allowable capital expenditures.**
   
   The depreciation provision is equal to 5% of the undepreciated cost of depreciable assets. The undepreciated cost of depreciable assets is the net balance at the end of the previous year plus the cost of additions in the year less the net undepreciated cost of disposals in the year. See Schedule I in Section 6.11 for a list of allowable capital expenditures and Schedule II in Section 6.11 for a list of capital expenditures that are not allowable.

3. **A return of 15.0% on invested capital.**
   
   Invested capital consists of:
   - the average undepreciated cost of depreciable assets between the beginning and the end of the year,
   - the cost of land on which the facility is located, and
   - an allowance for working capital equal to 1/6 of allowable direct operating costs incurred in the year.
ALLOWABLE EXPENDITURES cont’d

In determining what costs are allowable for GCA purposes it is important to distinguish between expenditures related to producing gas and delivering it to the plant (the “production function”) and expenditures related to processing the gas in the plant. The production function includes extraction, gathering, field compression, field dehydration, conservation, injection and activity related to oil production. Gathering, field compression and field dehydration costs are allowed for by the Producer Cost of Service allowance (PCOS). PCOS is based on standard costs for installed equipment and does not require reporting of actual costs incurred. Inclusion of costs related to the production function for GCA purposes will result in deduction of these costs twice.

X-REFERENCE

Completion Guidelines for the BC-23 are located in Section 6.11.
5.7 NATURAL GAS BY-PRODUCTS

Natural gas by-products means natural gas liquids, sulphur and substances other than marketable gas which are recovered from raw natural gas by processing or normal two phase field separation. Natural gas liquids means ethane, propane, butanes, pentanes or pentanes plus and any other condensates, or any combination of them, recovered from natural gas.

Royalty or tax is payable on natural gas by-products when they are sold. The royalty or tax share of natural gas liquids is valued at the sales value.

Where gas is processed in a plant, the sales value is the consideration received or receivable by the producer less actual costs incurred by the producer for transporting and processing the by-products from the point of production to the point of sale. By-product processing costs include the cost of stabilization and fractionation of an LPG mix into propane, butane and pentanes plus.

Costs incurred are subject to approval by the Administrator. Approved costs for sulphur include costs of storage, remelting, prilling, slating, cleaning, forming and freight to the point of sale. Costs that will not be approved are marketing fees, sales commissions, and administration costs, and any costs for processing or transportation after the point of sale.

X-REFERENCE

Specific details of the natural gas royalty calculation may be obtained by referring to Section 5.1, 5.2 and 7.0.
5.8 RAW GAS SALES

A relatively small volume of natural gas is sold for consumption in the field without being processed though a gas plant.

Section 4 of the royalty regulation states that royalty and tax must be paid on the value of ‘marketable gas’. Marketable gas means natural gas that is available for sale for direct consumption as a domestic, commercial or industrial fuel, or as an industrial raw material, whether it occurs naturally or results from the processing of natural gas. Raw gas that is sold in the field falls within this definition.

The determination of royalty or tax due on sales of raw gas is essentially the same as for residue gas. Volumes of raw gas sales are reported on a Marketable Gas and By-product Volumes and Values Report (BC08) for the well event that produced the raw gas for sale. The Ministry will issue a crown invoice to the producer, which calculates the royalty due on the BC08 raw gas sales volume using the royalty calculation procedures outlined in Section 5.1.
5.9 CREDITS AND EXEMPTIONS FROM NATURAL GAS ROYALTY/TAX

OVERVIEW

The following volumes are exempt from royalty and tax:

(1) Natural gas and natural gas by-products that, in the opinion of the royalty administrator, were lost without fault on the part of the producer and for which the producer received no compensation. In the case of gas or gas by-products that were lost, any compensation that is received for the loss, such as insurance proceeds, will be subject to royalty or tax.

(2) Natural gas or natural gas by-products used for oil and natural gas production, for drilling purposes or for injection into the formation from which they were produced, if the locations of production and use are held by the same producer or are both within the same unitized operation.

(3) Volumes from wells meeting conditions of discontinued incentive programs. See page 5.9-14 for description of the discontinued gas incentive programs.

(4) Natural gas and natural gas by-products produced from a deep discovery well event. A deep discovery well event is a gas well event that
   (a) is in a discovery well,
   (b) has a pay the top of which has a true vertical depth deeper than 4,000 metres,
   (c) is in a well that has a spud date after November 30, 2003, and,
   (d) is in a well that has a surface location at least 20 kilometres away from the surface location of any well in a recognized pool of the same formation;

See page 5.9-13 for description of the deep discovery well incentive program.

DEEP WELLS

Qualifying Criteria

A well qualifies for the deep well credit if it meets the following criteria:

- It has a spud date after June 30, 2003
- If the spud date is after June 30 and before December 1, 2003, for both vertical and horizontal wells, the deepest productive well event in the well has a true vertical depth (TVD) to the top of the producing zone (pay) of at least 2,500 metres.
- If the spud date is after November 30, 2003, the deepest productive well event in the well has a TVD to the top of pay greater than:
  - 2,500 meters if the well is a vertical well, and
  - 2,300 meters if the well is a horizontal wells.
DEEP WELL QUALIFYING CRITERIA cont’d

Horizontal wells are wells in which:

(a) the well bore in the well is drilled at an angle of at least 80 degrees from vertical, where the well bore is deemed to be a line connecting the well bore’s initial point of penetration into a productive zone to the well bore’s end point in that productive zone, and

(b) the length of the well bore referred to in (a) is at least 100 metres from the well bore's initial point of penetration into the productive zone to the well bore's end point in that productive zone.

Vertical wells are wells, including directional wells, that do not meet the criteria for horizontal wells.

TVD to the top of the pay for a well event is the distance between the point of intersection of the well bore and the top of the well event’s pay and a point directly above that is at the same elevation as the kelly bushing used in drilling the well.

No application forms are required. New data fields for TVD to Top of Pay and Measured Depth to Top of Pay have been added to the Notice of Commencement or Suspension of Operations (BC-11). Determination of eligibility will be based initially on this information as provided by the well operator on the BC-11. The Oil and Gas Commission will review the information for accuracy and ensure that the qualification criteria are met.

Calculating the Credit

The amount of the deep well credit is designed to approximately reflect higher drilling and completion costs. Since H₂S content, location, and depth can contribute to higher drilling and completion costs of a well, the credit is based on tables that reflect the impact of these attributes.

1. H₂S Content

For the purpose of the deep well credit, there are two categories of wells based on H₂S content: Sweet and Special Sour. Deep well events in wells classified as Special Sour are eligible for a greater credit than those in wells classified as Sweet. For a well to be classified as Special Sour, the maximum potential H₂S release rate from the well must be as follows:

(i) if the well is located within 500 metres of the corporate boundaries of an urban centre, 0.01 m³/s or greater and less than 0.1 m³/s,

(ii) if the well is located within 1.5 kilometres of the corporate boundaries of an urban centre, 0.1 m³/s or greater and less than 0.3 m³/s,

(iii) if the well is located within 5 kilometres of the corporate boundaries of an urban centre, 0.3 m³/s or greater and less than 2.0 m³/s, and

(iv) if the well is located 5 kilometres or more from the corporate boundaries of an urban centre, 2.0 m³/s or greater.

A Sweet well is a well that does not meet the criteria to be a Special Sour well.

The Deep Well Credit for deep well events in Special Sour wells is based on the Special Sour tables for East and West. The Deep Well Credit for deep well events in Sweet wells is based on the Sweet tables for East and West.

DEEP WELL QUALIFYING CRITERIA cont’d
2. Location

To recognize the higher costs associated with drilling in less accessible areas, there are two location categories: East and West. Locations that fall within the East category are in the following areas:

(i) that portion of Group 095-A-01 to Group 095-A-04 (inclusive);
(ii) that portion of Group 095-B-01 to Group 095-B-04 (inclusive);
(iii) Group 094-O-01 to Group 094-O-16 (inclusive);
(iv) Group 094-P-01 to Group 094-P-16 (inclusive);
(v) Group 094-I-01 to Group 094-I-16 (inclusive);
(vi) Group 094-J-01 to Group 094-J-16 (inclusive);
(vii) Group 094-G-01 to Group 094-G-16 (inclusive);
(viii) Group 094-H-01 to Group 094-H-16 (inclusive);
(ix) that portion of Group 094-A-01 to Group 094-A-16 (inclusive) that is located outside the Peace River Block;
(x) that portion of Group 093-P-09 that is located outside the Peace River Block;
(xi) that portion of Group 093-P-10 that is located outside the Peace River Block;
(xii) Groups 093-P-01, 093-P-02, 093-P-07 and 093-P-08;
(xiii) Group 093-I-16;
(xiv) Blocks A and G to K of Group 093-I-15;
(xv) Blocks A, B and F to K of Group 093-I-09;
(xvi) Block I of Group 093-I-08;
(xvii) the portion of the Peace River Block within Township 076 east of Range 20 W6M;
(xviii) the portion of the Peace River Block within Township 077 east of Range 20 W6M;
(xix) the portion of the Peace River Block within Township 078 east of Range 20 W6M;
(xx) the portion of the Peace River Block within Township 079 east of Range 20 W6M;
(xxii) the portion of the Peace River Block within Township 080 to Township 088 and Range 13 to Range 26 W6M,

When determining deep well deductions, tables labelled East apply to a well event if the well event is located in any of the areas described above. Areas referred to in items (i) to (xvi) above are in areas in which the NTS land survey system is used. Areas referred to in items (xvii) to (xxii) are described in accordance with the Dominion Land Survey System.

All locations other than those in the above areas are in the West category. When determining deep well deductions, tables labelled West apply to a well events not located in the areas described above.
DEEP WELL QUALIFYING CRITERIA cont’d

The following map shows the dividing line between the East and West Areas.

Ministry of Energy and Mines

Map Scale: 1:3320933

Map Center on: C-14-A/94-G-5
DEEP WELLS cont’d

Calculation of Deductible Amounts

Once the well event has been categorized into one of the four well event types based on bottom hole location and H₂S content, the amount that is deductible from royalties on gas produced from the deep well event is determined from the well’s Deep Well Depth using the following formula:

\[
( \text{Cumulative Value} + \text{Incremental Value} \times (\text{Deep Well Depth} – \text{Table Depth})) \times \text{PS}
\]

The meanings of the terms in this formula are as follows.

**PS**

PS is the producer’s proportionate interest in the deepest well event in the well. If there is more than one producer with an ownership interest in production from the deepest well event, each producer will be allocated a portion of the deep well Credit in accordance with their ownership share.

Deep well Credits related to a well event may only be deducted from royalties payable on gas or gas by-products produced from deep gas well events in the same well.

**Deep Well Depth**

Deep Well Depth means the Deep Well Depth of the deepest well event in the well.

Due to the modifications that were made in the deep well program on December 1, 2003, the Deep Well Depth of well events in wells with spud dates between July 1 and November 30, 2003 is different than for well events in wells with spud dates after November 30, 2003.

For well events in vertical and horizontal wells with spud dates between July 1 and November 30, 2003, Deep Well Depth is TVD to the top of the well event’s producing zone.

For well events in vertical wells with spud dates after November 30, 2003, Deep Well Depth is Measured Depth to the Top of Pay (MDTP).

For well events in horizontal wells with spud dates after November 30, 2003, the Deep Well Depth is the sum of,

(a) MDTP, and

(b) Horizontal Length Factor (HLF) x (Total Measured Depth – MDTP), where

- for well events with MDTOP greater than 2,300 metres and less than 2,875 metres,
  \[
  \text{HLF} = \frac{30 - .035 \times (\text{MDTOP} - 2,300)}{100}
  \]

- for well events with MDTP greater than 2,875 metres, HLF = .1

MDTP in relation to a well event is the measured distance along the well bore from the kelly bushing used in drilling the well to the intersection of the well bore with the top of the well event’s pay. The pay is the part of the producing zone where there is sufficient gas, pressure and permeability to justify commercial production. The Oil and Gas Commission will review and may vary the determination of the top of pay for a well event.
DEEP WELLS cont’d

Table Depth
Table Depth means the Deep Well Depth of the deepest well event rounded down to the nearest 500 metres. Table Depth determines which row in the appropriate table below is to be used to calculate the amount of deep well Credit for the well. For example, if the deepest well event has a Deep Well Depth of 3,785 metres, the 3500 metre row in the appropriate table is used.

Cumulative Value
Cumulative Value is the amount in the Cumulative Value column in the appropriate table that is in the same row as the Table Depth for the deepest well event. For example, for a West Special Sour well event with a Deep Well Depth of 3,785 metres, the Cumulative Value is $2,400,000, as shown in the 3500 metre row of the West Special Sour table.

Incremental Value
Incremental Value is the amount in the Incremental Value column in the appropriate table that is in the same row as the Table Depth for the deepest well event. It is the additional credit per metre of depth in excess of the Table Depth. For example, for a West Special Sour well event with a Deep Well Depth of 3,785 metres, the Incremental Value is $700 / metre, as in the 3500 metre row of the West Special Sour table.

<table>
<thead>
<tr>
<th>Depth (Metres)</th>
<th>West Special Sour</th>
<th>East Special Sour</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Cumulative Value ($)</td>
<td>Incremental Value ($/Metre)</td>
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<tr>
<td>2500</td>
<td>0</td>
<td>4200</td>
</tr>
<tr>
<td>3000</td>
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</tr>
</tbody>
</table>

<table>
<thead>
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<th>West Sweet</th>
<th>East Sweet</th>
</tr>
</thead>
<tbody>
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<td></td>
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<td>Incremental Value ($/Metre)</td>
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<tr>
<td>4500</td>
<td>2,825,000</td>
<td>800</td>
</tr>
<tr>
<td>5000</td>
<td>3,225,000</td>
<td>900</td>
</tr>
<tr>
<td>5500</td>
<td>3,675,000</td>
<td></td>
</tr>
</tbody>
</table>

DEEP WELLS cont’d
EXAMPLE 1

Following is an example of the calculation of the amount of the deep well credits for a well with the following attributes:

- **spud date:** after November 30, 2003
- **type of well:** vertical
- **gas quality:** Special Sour
- **location:** West area
- **MDTP:** 3,785 metres
- **Ownership of deepest well event:** 60% Producer A, 40% Producer B

Calculation of the amount of the deep well credit for this well would be as follows:

\[
\text{Deep Well Depth} = \text{MDTP} = 3,785 \text{ metres} \\
\text{Table Depth} = \text{Deep Well Depth rounded down to nearest 500 metres} = 3,500 \text{ metres} \\
\text{Cumulative Value} = \text{amount in 3500 row in the West Special Sour table} = \$2,400,000 \\
\text{Incremental Value} = \text{amount in 3500 row in the West Special Sour table} = \$700 \text{ per metre} \\
\text{Deep well credit} = 2,400,000 + 700 \times (3,785 - 3,500) = \$2,599,500 \\
\text{Credit available to Producer A} = 60\% \text{ of 2,599,500} = \$1,599,700 \\
\text{Credit available to Producer B} = 40\% \text{ of 2,599,500} = \$1,039,800
\]

Note that the allocation of the deep well credit to producers is based on ownership of the deepest well event only. For example, if Producer A owned 100% of another well event in this well with a Deep Well Depth of 3,550 metres, Producer A would still be allocated \$1,599,700. However, this deep well credit would be allocated on the crown invoice against royalties payable on production from both of Producer A’s deep well events.
DEEP WELLS cont’d

EXAMPLE 2

Following is an example of the calculation of the amount of the deep well credit for a well with the following attributes:

- **spud date:** after November 30, 2003
- **type of well:** horizontal
- **gas quality:** Sweet
- **location:** East area
- **MDTP:** 2,655 metres
- **Total Measured Depth:** 2,910 metres
- **Ownership of deepest well event:** 50% Producer A, 50% Producer B

Calculation of the amount of the deep well credit for this well would be as follows:

- **Deep Well Depth**
  \[
  \text{Deep Well Depth} = \text{MDTP} + \frac{\text{Horizontal Length Factor} \times (\text{Total Measured Depth} - \text{DTOP})}{100} \\
  = 2,655 + \frac{0.035 \times (2,655 - 2,300)}{100} \times (2,910 - 2,655) \\
  = 2,655 + 0.17575 \times 255 \\
  = 2,699 \text{ metres}
  \]

- **Table Depth**
  \[
  \text{Table Depth} = \text{Deep Well Depth rounded down to nearest 500 metres} \\
  = 2,500 \text{ metres}
  \]

- **Cumulative Value**
  \[
  \text{Cumulative Value} = \text{amount in 2500 row in the East Sweet table} \\
  = 0
  \]

- **Incremental Value**
  \[
  \text{Incremental Value} = \text{amount in 2500 row in the East Sweet table} \\
  = $1400 \text{ per metre}
  \]

- **Deep well credit**
  \[
  \text{Deep well credit} = 0 + 1400 \times (2,699 - 2,500) \\
  = $278,600
  \]

**Credit available to Producer A**
\[
= 50\% \text{ of } 278,600 = $139,300
\]

**Credit available to Producer B**
\[
= 50\% \text{ of } 278,600 = $139,300
\]
DEEP WELLS cont’d

EXAMPLE 3
Following is an example of the calculation of the amount of the deep well credit for a well with the following attributes:

- **spud date:** after November 30, 2003
- **type of well:** horizontal
- **gas quality:** Sweet
- **location:** West area
- **MDTP:** 3,100 metres
- **Total Measured Depth:** 5,400 metres
- **Ownership of deepest well event:** 80% Producer A, 20% Producer B

Calculation of the amount of the deep well credit for this well would be as follows:

**Deep Well Depth**
\[
= \text{MDTP} + \text{Horizontal Length Factor} \times (\text{Total Measured Depth} - \text{DTOP})
\]
\[
= 3,100 + 0.1 \times (5,400 - 3,100)
\]
\[
= 3,100 + 0.1 \times 2,300
\]
\[
= 3,330 \text{ metres}
\]

**Table Depth**
\[
= \text{Deep Well Depth} \text{ rounded down to nearest 500 metres}
\]
\[
= 3,000 \text{ metres}
\]

**Cumulative Value**
\[
= \text{amount in 3000 row in the West Sweet table}
\]
\[
= \$1,900,000
\]

**Incremental Value**
\[
= \text{amount in 3000 row in the West Sweet table}
\]
\[
= \$550 \text{ per metre}
\]

**Deep well credit**
\[
= 1,900,000 + 550 \times (3,330 - 3,000)
\]
\[
= 1,900,000 + 550 \times 330
\]
\[
= 1,900,000 + 182,500
\]
\[
= 2,081,500
\]

Credit available to Producer A
\[
= 80\% \text{ of } 2,081,500 = \$1,665,200
\]

Credit available to Producer B
\[
= 20\% \text{ of } 2,081,500 = \$416,300
\]
DEEP RE-ENTRIES

Qualifying Criteria

Re-entry well event qualifies for the deep re-entry credit if it meets the following criteria:
- the re-entry date is after November 30, 2003
- an Application to Alter a Well has been submitted to the Oil & Gas Commission and approved before the re-entry date
- the deepest productive well event in the well has a true vertical depth (TVD) to the top of pay greater than 2,300 metres.

Calculating the Credit

As with the Deep Well Credit, the amount of the Deep Re-entry Credit is also designed to approximately reflect higher drilling and completion costs. For deep re-entries the credit is based on location and the additional amount of drilling that is done in the well, i.e. its Incremental Distance. To recognize the higher costs associated with drilling in less accessible areas, the same East and West location categories used for the Deep Well Credit are used for Deep Re-entry Credit.

Once the location and Incremental Distance have been determined, the amount that is deductible from royalties on gas produced from deep re-entry well events is determined using the following formula:

\[
( \text{Cumulative Value} + \text{Incremental Value} \times (\text{Incremental Distance} - \text{Table Distance}) ) \times PS
\]

The meanings of the terms in this formula are as follows.

PS

PS is the producer’s proportionate interest in the deepest re-entry well event in the well. If there is more than one producer with an ownership interest in production from the deepest well event, each producer will be allocated a portion of the deep well credit in accordance with their ownership share.

Deep Re-entry Credits related to a well event may only be deducted from royalties payable on gas or gas by-products produced from deep gas well events in the same well.

Incremental Distance:

Incremental Distance is the difference between the Total Measured Depth (TMD) of the well after it was altered and the TMD before it was altered. The TMD of a well is the sum of the lengths of all the well bores in the well, including vertical and horizontal well bores.
DEEP RE-ENTRIES cont’d

Table Distance:
Table Distance means the Incremental Distance rounded down to the nearest corresponding number in the Table Distance column of the tables in Schedule 3. For example, if the re-entered well had a TMD of 5,000 metres before alteration and 5,450 metres after alteration, the Incremental Distance would be 450 metres and the Table Distance would be 300 metres. The 300 metre row in the appropriate table is used.

Cumulative Value
Cumulative Value is the amount in the Cumulative Value column in the appropriate table that is in the same row as the Table Distance. For example, for a deep re-entry in the West area with Table Distance of 300 metres, the Cumulative Value is $150,000, as shown in the 300 metre row of the West table.

Incremental Value
Incremental Value is the amount in the Incremental Value column in the appropriate table that is in the same row as the Table Distance for the re-entry. It is the additional credit per metre of Incremental Distance in excess of the Table Distance. For example, for a re-entry located in the West area with Incremental Distance of 150 metres, the Incremental Value is $500 / metre, as in the 300 metre row of the West table.

<table>
<thead>
<tr>
<th>West</th>
<th>East</th>
</tr>
</thead>
<tbody>
<tr>
<td>Table Distance (Metres)</td>
<td>Cumulative Value ($)</td>
</tr>
<tr>
<td>100</td>
<td>0</td>
</tr>
<tr>
<td>300</td>
<td>150,000</td>
</tr>
<tr>
<td>1500</td>
<td>750,000</td>
</tr>
</tbody>
</table>

EXAMPLE
Following is an example of the calculation of the amount of the Deep Re-entry Credit for a re-entry with the following attributes:

- spud date: after November 30, 2003
- location: East area
- TMD before alteration: 1,800 metres
- TMD after alteration: 2,900 metres
- ownership of deepest well event: 60% Producer A, 40% Producer B
DEEP RE-ENTRIES cont’d

Calculation of the amount of the Deep Re-entry Credit for this re-entry would be as follows:

Incremental Distance = 2,900 – 1,800 = 1,100 metres
Table Distance = Incremental Distance rounded down to nearest amount in the Table Distance column of the East table = 300 metres
Cumulative Value = amount in 300 row in the East table = $90,000
Incremental Value = amount in 300 row in the East table = $300 per metre
Deep Re-entry Credit = 90,000 + 300 x (1,100 – 300) = $330,000
Credit available to Producer A = 60% of 330,000 = $198,000
Credit available to Producer B = 40% of 330,000 = $132,000

USING DEEP WELL CREDITS TO REDUCE ROYALTIES

Deep well credits can only be used to reduce royalties on production of gas and by-products from deep well events in that well. Deep well credits cannot be deducted from royalties on production from well events in the same well that are not deep well events or from well events in other wells.

When the Ministry receives BC11 reports with True Vertical Depth and Measured Depth to Top of Pay that indicates the well event is a deep well event, the Ministry will use this and other information to calculate the amount of the deep well credit. No action is required on the part of producers with interests in the well event. An email is sent to each producer which will show their share of the deep well credit for the well.

Producers should report all marketable gas production from deep well events on Marketable Gas and By-Product Producer Allocations (BC08) reports. Gas royalty invoices for the deep well events will show the amount of deep well credit used to reduce royalties on the invoice and the remaining unused balance of the deep well credit.

DEEP DISCOVERY WELL EXEMPTION

The Deep Discovery Well Exemption provides royalty relief in addition to Deep Well and Deep Re-entry Credits to encourage higher risk exploration drilling.
QUALIFYING CRITERIA

A well event must meet the following criteria to qualify for the Deep Discovery Well Exemption.

1. It must be a discovery well, which is defined in the Drilling and Production Regulation (B.C. Reg. 336/91) as a well from which, in the opinion of an authorized employee of the Oil & Gas Commission, there is sufficient information to indicate it has encountered a previously undiscovered pool.

2. It must have a pay the top of which has a true vertical depth of 4,000 metres or more.

3. It must have a rig release date after November 30, 2003.

4. It must be in a well with a surface location that is at least 20 kilometres from the surface location of any well in a recognized pool of the same formation.

The Oil & Gas Commission will provide the well operator with written notification when a well event discovers a new gas pool. The Ministry of Small Business and Revenue will notify producers having ownership interests in the well event if the well event qualifies for the Deep Discovery Well exemption.

CALCULATING THE EXEMPTION

A deep discovery well event is exempt from royalties for 36 months or on 283 million m$^3$ of raw gas production, whichever comes first.

Volumes of marketable gas produced from a deep discovery well event must be reported on a Marketable Gas and By-Products Producer Allocations (BC08) report each month. The ministry will issue a gas royalty invoice each month that will indicate value of the exempt royalty share, the number of exempt months and exempt production of natural gas.

A deep discovery well event is also eligible for the Deep Well Credit. To ensure producers receive the full value of the Deep Well Credit for a deep discovery well event, the ministry will calculate the amount of Deep Well Credit for deep discovery well events and will deduct the value of the exempt royalty share against the credit each month. If at the end of the Deep Discovery Well Exemption the cumulative value of the exempt royalty share is less than the Deep Well Credit, the difference will be deducted from gross royalties for the well event after the Deep Discovery Well Exemption has expired.
DISCONTINUED INCENTIVE PROGRAMS

Section 6(3) of the royalty regulation continued the exempt status of gas wells that were exempt under section 5(3) of the previous royalty regulation (Regulation 222/88, ‘Petroleum and Natural Gas Royalty Regulation’) until the exemption expires in accordance with the provision under which it was granted. Regulation 222/88 was repealed in 1992 and replaced by the current royalty regulation.

Under that incentive program, wells that were within a specified area (Area A) and commenced drilling after May 31, 1987 and before June 1, 1989 were granted the following exemptions:

1. exploratory wildcat wells:
   - completed as pre-mesozoic - exempt for the first 24 producing months
   - completed as mesozoic or post-mesozoic - exempt for the first 12 producing months

2. any other wells - exempt for the first 12 producing months.

Wells that were not within Area A and commenced drilling after May 31, 1987 and before June 1, 1990 were granted the following exemptions:

1. exploratory wildcat wells:
   - completed as pre-mesozoic - exempt for the first 36 producing months
   - completed as mesozoic or post-mesozoic - exempt for the first 18 producing months

2. any other wells - exempt for the first 12 producing months.