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Tenure
Freehold Mineral Tax

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File No.

November 12, 2003

TO: ***Owners, Lessees, and Operators of Freehold Mineral Rights***

RE: FREEHOLD MINERAL RIGHTS TAX ACT
PETROLEUM AND/OR NATURAL GAS RIGHTS
UNIT VALUES FOR 2003 TAXATION YEAR

The Freehold Mineral Rights Tax Act (FMRTA) requires the annual submission of information for use in calculating tax payable with respect to the production of freehold petroleum and natural gas. Pursuant to Section 8 of the FMRTA, the Department of Energy requests the submission of unit values on or before **January 13, 2004**.

The attached guidelines have been updated to clarify revenue and allowable costs. We encourage you to refer to these when calculating your unit values.

In it's continuing effort to standardize the unit value calculation, the department's preferred methodology includes the following components:

- Reporting period – use October 1 to September 30 (3 + 9)
- Revenue –
  - We are encouraging the use of the Crown Gas Invoice Valuation Prices (by product) - October 1, 2002 to September 30, 2003 (3+9)
- Costs – use:
  - Unit Operating Cost Rates (UOCR) – previous calendar year
  - Capital costs – previous calendar year
  - Custom fee costs – October 1 to September 30 (3 + 9)

Standardizing the unit value calculation will minimize any difficulties arising from the amalgamation of company information resulting from mergers, acquisitions and dispositions.

In the attached guidelines, the options for calculating unit values for gas and/or solution gas are listed in order of preference, with the department's preferred methodology shown first. Companies will still have the option of using alternate methods, but we request that you explain in writing why you choose not to go with a standardized methodology so we can deal with these on an exception basis.

To assist you in filing your unit values for 2003, a submission document is enclosed that shows single well and multiple well production entities associated with Freehold mineral titles in which, according to the department's records, you have a declared interest. Blank spaces have been provided to identify the products from each production entity for which a unit value is required.

In cases where the identified well status as at December 31 of the taxation year differs from that shown on the unit value submission document, the department reserves the right to make any necessary adjustments to match the unit value submitted to the product to be taxed.

This document may not include all your production entities; therefore, you may need to identify additional production entities and corresponding unit values on your document. To have your unit values recognized for these production entities, please fill out the attached "Lessee Linkage Form" requesting a linkage to the Title IDs covering the land associated with the additional production entities. If you do not establish a lessee linkage the department cannot recognize your submitted unit value and, as a result, the department will use a Default unit value.

Please note the following when completing your submission document:

- Unit values should be submitted only for those production entities in which you have a Freehold interest.

- If you have **no interest** in a production entity, write “no interest” in the “remarks” column.

- Zero values are acceptable in some situations (e.g. cost exceeds revenues, gas was flared or gas was used for lease fuel). In these cases please provide an explanation in the “remarks” column.

- If you wish to create your own submission document, the format <u>must</u> be identical to the department’s to be accepted. Each well identifier must include the Location and Event.

- Identify the reporting period used for the unit value calculation on page one of the document. Please indicate the method used beside the reporting period using the corresponding letter in the Guidelines.

- In the spaces provided on page one please include a contact name and telephone number for a person we can call to discuss any concerns we might have about the information provided.

- For electronic submissions, please identify the reporting period and methodology used as well as a contact name and telephone number on your return email or covering letter.

The unit values that you submit are subject to audit by the department. You must, therefore, retain a copy of your unit value calculations with all supporting documentation and provide them to the department upon request.

Submissions of the required information will help the department calculate a fair and equitable tax. Failure to submit the necessary unit values will result in the department issuing a 2003 tax statement using default values.

If you require further information, please contact Ramona Lofgren at (780) 422-9349, Cornelia McCoy at (780) 415-6592, or myself at (780) 427-8956.

Yours truly,

Brenda Curle
Manager
Freehold Mineral Tax

Freehold Mineral Tax Unit Value Guide - 2003

ALBERTA ENERGY
FREEHOLD MINERAL RIGHTS TAX
GUIDELINES FOR DETERMINING UNIT VALUES
2003 TAXATION YEAR
Effective November 12, 2003

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Freehold Mineral Rights Tax is calculated annually using calendar year petroleum and natural gas wellhead production which is allocated to the mineral rights owners of each tract within a production entity.

If the revenues used to calculate unit values for gas and/or solution gas or oil or condensate represents a working interest percent of total revenues, the costs determined and the production at the wellhead should also represent that same working interest.

In cases where the well status at December 31 of the taxation year differs from that identified on the unit value submission document, the department reserves the right to make any necessary adjustments to match the unit value to the product to be taxed.

In all cases, cost allowances are calculated for a reporting period. Any costs exceeding the determined gross revenues cannot be carried forward to a following reporting period.

STANDARDIZING UNIT VALUE CALCULATIONS FOR GAS AND/OR SOLUTION GAS.

In an effort to streamline the unit value calculation process, the department would like to standardize the unit value calculation in the following areas:

- Reporting period – use October 1, 2002 to September 30, 2003 (3 + 9) production period.
- Revenue –
  - We are encouraging the use of the Crown Valuation Price (by product) to determine revenues. Use of Valuation Price should also follow the same reporting period of October 1, 2002 to September

30, 2003 (3 + 9). The Valuation Prices are those values reported on your electronic monthly Crown Gas Royalty Detail invoice.

- Costs – use:
  - Unit Operating Cost Rates (UOCR) – previous calendar year
  - Capital costs – previous calendar year
  - Custom fees – October 1, 2002 to September 30, 2003 (3 + 9) production period.

Once a methodology and reporting period have been chosen, they must be consistently used from property to property and year to year.

I. CALCULATION OF UNIT VALUE FOR GAS AND/OR SOLUTION GAS

Unit values for gas and/or solution gas can be calculated using one of the following three methods.

The methods are listed in order of preference.

METHOD A: USING CROWN GAS ROYALTY INFORMATION

THIS IS THE DEPARTMENT'S PREFERRED METHOD

This method mirrors Crown Gas Royalty reporting and employs the use of Crown Invoice Valuation Pricing, Crown Unit Operating Cost Rates (UOCR), Crown Capital Cost Allowances and actual custom fees.

1. Unit Value ($) =

Revenues (**2**) – Allowable Costs (**3**)

Gas or Solution Gas Production (**4**)

2. Determine revenues ($) pertaining to the production of gas and/or solution gas using the Crown invoice valuation prices for the production months October 1, 2002 to September 30, 2003. The valuation prices should be applied to the Client Volumetric Totals - Quantity/ Heat for all product types (e.g. gas, ethane, propane, butane, pentanes and sulphur) from the production entity processed at each facility.

NOTE:

Valuation prices already incorporate gas in-stream Facility Average Prices (FAP), raw gas sales, transportation and fractionation adjustments.

Use of valuation prices requires an adjustment of volumes where portion(s) of the volumes reported are re-injected into the same field and pool. Please refer to the Injected Gas (SECTION IV) for further information.

3. Using the same reporting period, determine the allowable costs by using:

A. The department's posted Unit Operating Cost Rates (UOCR) for 2002 (effective February 2002) and applicable capital costs for 2002, Or

B. Actual custom processing fees for October 1, 2002 to September 30, 2003, provided those costs are reasonable, Or

C. In situations where companies do not have ownership in the entire gathering, compressing and processing functions, the applicable de-layered UOCR, custom fees and capital costs are eligible. Please note that de-layered UOCR and custom fees cannot be claimed for the same function.

For example: You have ownership in the compression and processing facilities and also in three of the four gathering systems used by the gas stream under consideration.

1. You are eligible for the de-layered UOCR for the compressing and processing functions.

2. A choice has to be made regarding the operating costs for the gathering function. You can claim either:

a. The de-layered UOCR for the gathering function, or

b. The custom fees incurred for the gathering system where you have no ownership.

You cannot claim both the gathering de-layered UOCR and the custom fees incurred.

For excess capacity at a facility (i.e. volume exceeding the proprietary share) only the custom fees incurred for the excess capacity are eligible. UOCR cannot be claimed for the excess volume as the custom fees have already included fees for both the operating and capital components. Please note that operating costs cannot be claimed for raw gas sales.

4. Using the same reporting period, determine the total gas or solution gas production (10^3m^3) at the wellhead for all wells that contributed to the revenues calculated under item 2. The volumes are those as reported to the Energy and Utilities Board (EUB) through the Petroleum Registry of Alberta.

5. Deduct allowable costs (**3**), if any, from total revenues (**2**) and divide by gas and/or solution gas production (**4**) to determine the unit value.

6. Record the unit value to all appropriate production entities on the submission document and remember to include any notes in the “remarks” column.

USING UNIT OPERATING COST RATES (UOCR)

NOTE:

For both Methods A and B the UOCR are expressed in terms of dollars per 10^3m^3 of energy adjusted-equivalent volumes. The volumes used for revenue in A (2) or B (2) for gas and by-products should be converted to energy adjusted gas equivalent volumes to which the UOCR is applied to obtain allowable operating cost. The energy-adjusted gas equivalent factors are as follows:

GAS in 10^3m^3 x 1.00000

ETHANE in m^3 x 0.28132

PROPANE in m^3 x 0.65554

BUTANE in m^3 x 0.72793

PENTANES-PLUS in m^3 x 0.78783

SULPHUR in tonnes x 0.73750

You may wish to refer to the Department's Gas Royalty Guidelines or, contact the Freehold Mineral Tax office for further information and assistance in the use of Crown Gas Royalty Information in calculation of your unit values.

ALLOCATING CAPITAL COSTS

Methods of determination:

- To avoid the complexity of allocating capital costs to well/unit level, you can group production entities by gas plant, or by gathering system where there is no gas plant involved. A unit value for the group can then be calculated using total revenues, costs and production for all of the streams in the group. Capital costs associated with the gathering, compression and processing of non-Alberta volumes and volumes purchased from a third party should be excluded.
- Determine actual capital costs by tracking the actual flow for each well/unit and prorate the costs in each facility by throughput volume. Detailed schematic records must be kept.
- Allocate capital costs using the percentage of energy adjusted gas equivalent volumes (EAGEV) of the stream as compared to the total EAGEV processed at the plant. The volumes used should be from the same calendar year as the capital costs. For facilities with non-Alberta volumes, physical assets that handle out of province volumes exclusively should be allocated only to non-Alberta volumes.

In each of the above methods, it is recommended that you use your share of allocated capital costs rather than the total facility capital costs.

Once a method of Capital Cost determination has been selected, that method must be consistently used from property to property and year to year.

METHOD B: USING ACTUAL GROSS REVENUES LESS CROWN ROYALTY ALLOWABLE COSTS RATES

This method requires use of actual stream revenues. For costs, the "Allowable Cost" rates used for Crown purposes such as Capital Cost Allowances, Unit Operating Cost Rates (UOCR), and where applicable, Actual Custom Fees are allowed.

1. Unit Value ($) =

Revenues (**2**) – Allowable Costs (**3**)

Gas or Solution Gas Production (**4**)

2. Determine gross revenues ($) pertaining to the sale of gas and/or solution gas from a production entity for the period October 1, 2002 through September 30, 2003. This includes revenues from all by-products (e.g. gas, ethane, propane, butane, pentanes and sulphur).

3. Using the same reporting period, determine the allowable costs by using:

A. The department's posted Unit Operating Cost Rates (UOCR) for 2002 (effective February 2002) and applicable capital costs for 2002, Or

B. Actual custom processing fees for October 1, 2002 to September 30, 2003, provided those costs are reasonable, Or

C. In situations where companies do not have ownership in the entire gathering, compressing and processing functions, the applicable de-layered UOCR, custom fees and capital costs are eligible. Please note that de-layered UOCR and custom fees cannot be claimed for the same function.

For example: You have ownership in the compression and processing facilities and also in three of the four gathering systems used by the gas stream under consideration.

You are eligible for the de-layered UOCR for the compressing and processing functions.

A choice has to be made regarding the operating costs for the gathering function. You can claim either:

a. The de-layered UOCR for the gathering function, or

b. The custom fees incurred for the gathering system where you have no ownership.

You cannot claim both the gathering de-layered UOCR and the custom fees incurred.

For excess capacity at a facility (i.e. volume exceeding the proprietary share) only the custom fees incurred for the excess capacity are eligible. UOCR cannot be claimed for the excess volume as the custom fees have already included fees for both the operating and capital components.

Please note that operating costs cannot be claimed for raw gas sales.

4. Using the same reporting period, determine the total gas or solution gas production (103m3) at the wellhead for all wells that contributed to the revenues calculated under item 2. The volumes are those as reported to the EUB through the Petroleum Registry of Alberta.

5. Deduct allowable costs (**3**), if any, from total revenues (**2**) and divide by gas and/or solution gas production (**4**) to determine the unit value.

6. Record the unit value to all appropriate production entities on the submission document and remember to include any notes in the “remarks” column.

METHOD C: USING ACTUAL GROSS REVENUES LESS ACTUAL ALLOWABLE COSTS

1. Unit Value ($) =

Revenues (**2**) – Allowable Costs (**3**)

Gas or Solution Gas Production (**4**)

2. Determine gross revenues ($) pertaining to the sale of gas and/or solution gas from a production entity for the period October 1, 2002 through September 30, 2003. This includes revenues from all by-products (e.g. gas, ethane, propane, butane, pentanes and sulphur).

3. Using the same reporting period, determine allowable costs ($). Allowable costs are those actual costs incurred for capital cost allowances, gathering, compressing, processing and/or custom processing fees for field gas and/or solution gas, provided those costs are reasonable.

4. Using the same reporting period, determine the total gas or solution gas production (10^3m^3) at the wellhead for all wells, which contributed to the revenues calculated under item 2. The volumes are those as reported to the EUB through the Petroleum Registry of Alberta.

5. Deduct allowable costs (**3**), if any, from total gross revenues (**2**) and divide by gas and/or solution gas production (**4**) to determine the unit value.

6. Record the unit value to all appropriate production entities on the submission document and remember to include any notes in the "remarks" column.

II. CALCULATION OF UNIT VALUE FOR CRUDE OIL AND/OR GAS WELL CONDENSATE.

1. Unit Value ($) =

Revenues (**2**) – Allowable Costs (**3**)

Crude Oil or Gas Well Condensate Production(**4**)

2. Determine gross revenues ($) received pertaining to the sale of crude oil or gas well condensate from a production entity for the same reporting period as in your gas and/or solution gas calculations (**SECTION I.)**

3. Using the same reporting period, determine allowable costs ($). Allowable costs are those actual costs incurred for transportation of clean oil or gas well condensate from the point of first measurement of the clean oil to a pipeline inlet or first point of sale.

4. Using the same reporting period, determine the total crude oil or gas well condensate production (m3) at the wellhead for all wells that contributed to the revenues calculated under item 2. The volumes are those as reported to the EUB through the Petroleum Registry of Alberta.

5. Deduct allowable costs (**3**), if any, from total gross revenues (**2**) and divide by crude oil and/or gas well condensate production (**4**) to determine the unit value.

6. Record the unit value to all appropriate production entities on the submission document.

III. FLARED AND/OR LEASE FUEL

1. Calculate a unit value for flared or lease fuel gas in the same manner as for field or solution gas.

2. Where the total volume of the gas produced has been flared or used as lease fuel and there are no sales or realized revenues, then the unit value would be $0.00.

However, if only a portion of the gas produced has been flared or used as lease fuel and the remaining portion has been sold, the revenues are to be used in the calculation of a unit value. Dividing the revenues by the total production will result in a lower unit value, thus compensating for the portion of the gas flared or used as lease fuel.

3. Record the unit value to all appropriate production entities on the submission document. Also, note in the "remarks" column that the gas has been flared or utilized as lease fuel, etc.

IV. INJECTED GAS

1. If gas and liquids are injected into a different field or pool than that from which they were originally produced, a unit value is required because the gas injected is considered to have undergone a change in ownership, thereby realizing revenue and full tax obligations being incurred.

2. In cases where all gas and liquids are injected into the same field and pool from which they were originally produced, the submission of a $0.00 unit value is required. In the "remarks" column indicate that the volumes in question have been "**injected into their native pool**".

Invoiced client volumes for the Crown Gas Royalty (CR) charge type are based on processed volumes at the plant outlet. Invoiced client volumes for the Injection Credit (IC) charge type are related to injection.

The revenue adjustment can be achieved by reducing Unit Value Revenue in Method A by the corresponding invoiced client volumes for the related Injection Credit transactions.

3. If only a portion of the gas and liquids produced was injected into the same field and pool and the remaining portion was sold, the revenues of the native products sold should be used in the calculation of the unit value. The net revenue should be divided by the total production volumes. This will result in a lower unit value, thus compensating for levying tax on the injected volumes.

Operating and capital costs associated with the gathering, compression and processing of reproduced native products, whether sold or re-injected, are considered to be eligible costs.

It is the responsibility of the companies to maintain detailed records of the volumes of injected and reproduced native and non-native products.

Companies should also maintain documentation to substantiate the sources of non-native products injected.

4. Record the unit value and remarks for all appropriate production entities on the submission document.

V. NEW WELL

If a new well is commissioned during the reporting period, unit values must be calculated using the same methodology as in SECTION I, (revenue and allowable costs) over the balance of the reporting period.

For example: A unit value for a new well placed on production in July would use the following information (Method A):

Reporting period: July 2003 – September 2003 (3 months instead of 12)

Revenue: Valuation price, by product, using Client Volumetric Totals - Quantities/Heat.

Allowable Costs:

> a) Estimate of current year's allowable capital costs (I.e. using capital costs corresponding to the reporting period) and
>
> b) Applicable previous year's UOCR effective February 2003 using energy-adjusted gas equivalent Crown Client Volumetric Quantities/Heat from July 2003 – September 2003 and/or
>
> c) For volumes where the UOCR does not apply, actual custom fees for July 2003 – September 2003.

Production: Production volumes for July 2003 – September 2003.

In cases where the well is commissioned after the reporting period but before the end of the taxation year estimates are to be made for the balance of the taxation year on revenue and allowable costs. These are to be used along with actual production volumes for the same period in the unit value calculation(s).

The next year's unit value calculation should then follow the standard reporting period and methodology used by your company.

For the wells commissioned after the reporting period, some information from the same months will be re-used in the next year's unit value calculations.

VI. SIGNIFICANT PRODUCTION OR CAPITAL CHANGE

If significant production or capital changes occur (e.g. new well, sales of properties, shut-in or major capital additions), capital costs corresponding to the reporting period should be used. This may involve the use of the previous year's actual capital costs and an estimate of the current year's capital costs. The estimate can then be adjusted to actual in the following year. In the following year, the previous year's capital costs should be used (i.e. the same capital costs would be used in two consecutive years).

Please indicate "Significant Production or Capital Change" in the "remarks" column of the unit value submission document.

VII. PRIOR PERIOD ADJUSTMENTS

Revenue, cost and production changes processed after the initial unit value filings should be accounted for either by amending the unit value in the affected year, or, by incorporating the adjustments into the current year unit value filings as prior year adjustments.

For companies using actual revenues, prior year revenue adjustments can be captured from the financial data by extracting all sales transactions processed in the accounting months relating to the production period under consideration.

For example: A company's regular reporting period is October 2002 to September 2003 and they have one-month lag between production month and accounting month. The sales transactions extracted for the accounting months of November 2002 to October 2003 will include any prior period adjustments relating to the production months prior to October 2002. Where the effect of the prior period adjustment is immaterial it is recommended that the adjustment be included in the current year unit value calculations. Detailed documentation of the prior year adjustments must be kept for audit purposes.

Where the effect of the prior period adjustment is material a revision to the original unit value submission is necessary.

VIII. AMENDING AND APPEALING UNIT VALUES

For the 2003 tax year, amendments to unit values due to new or corrected information should be forwarded to Freehold Mineral Tax as soon as possible and no later than **December 31, 2005**. This will allow the Department time to review the information and revise the tax in accordance with section 3 (3) and 3 (5) of the Freehold Mineral Rights Tax Act. If the effect of the amendment is immaterial, the amended information should be included in the following year's calculations. Should circumstances warrant the amending of unit values after December 31, 2005, a written request must be made to provide detailed information on the specific reason for the amendments and the estimated tax impact. Appeals are usually due to policy interpretation. Should you wish to formally appeal the assessed unit value for the 2003 tax year, a written appeal notification along with copies of all supporting information should be submitted as specified in the Freehold Mineral Rights Tax Act. Pursuant to section 11 (2) of the Freehold Mineral Rights Tax Regulation, the deadlines for formal appeals are July 15, 2004 for 2003 tax statements and 90 days after the date of issue on any new or corrected tax statements. Freehold Mineral Tax will endeavour to resolve the appeal to the mutual satisfaction of all affected parties.

All unit value submissions are subject to audit by the department's Compliance and Assurance unit.

IX. RECORD RETENTION

Records relating to the production, revenue and costs of 2003 Freehold Minerals production are subject to review by the Department's Compliance and Assurance unit until December 31, 2007 and must be made available in a timely manner upon request.