Freehold Mineral Tax 2017 Unit Value Submission Guide

General Information

Freehold Mineral Rights Tax is calculated annually on calendar year wellhead production of petroleum and natural gas. The tax on production is allocated to the mineral rights' owners of each tract within a production entity. This guide describes the calculation of a Unit Value (UV) of wellhead freehold production using the revenue and allowable costs of the production entity.

- The 2017 annual tax calculation will be assessed on or before **March 26, 2018**. **Payment is due April 25, 2018**.
- Alberta Energy calculates a default unit value for gas at 80% of the weighted average Crown gas reference prices. The default unit values for oil are calculated on the Alberta Petroleum Marketing Commission (APMC) average oil prices. The default value for bitumen is calculated on the average Hardisty bitumen prices.

  The final 2017 default prices up to December 31, 2017 are:

  Gas - \$63.00/10^3m^3
  Solution Gas - \$63.00/10^3m^3
  Light-Medium Oil - \$362.00/m^3
  Heavy Oil - \$285.00/m^3
  Bitumen - \$267.00/m^3
  Condensate - \$362.00/m^3

  Please Note: the guidelines for 2017 default unit values have now been updated and finalized with the January 2017 to December 2017 calendar production months.

  If no unit value is submitted for a production entity/product, the department will use the default values to calculate the tax payable. If you choose to report unit values for the 2017 tax year, the submission date is **noon (12:00 p.m.) March 9, 2018**. The method of calculating a Unit Value for Freehold Mineral Tax must be consistent for all properties and all years. To request a change in UV calculation method, contact the department, Freehold Mineral Tax, 7th Floor, 9945 – 108 St., Edmonton, AB T5K 2G6.

- The reporting period for capturing production and revenue for the 2017 unit value calculation, is the production months from **January 2017 to December 2017 (calendar year)**.
- When reporting a working interest ownership percentage (WIO %), use the same WIO% to determine revenue, costs and production. Any costs exceeding gross revenues cannot be carried forward to a future reporting period.
- For additional information access our website http://www.energy.alberta.ca/AU/MO/Pages/Freehold.aspx or contact the Freehold Mineral Tax unit at 780-427-6000 (310-0000 Alberta Toll Free) or e-mail Mintax.Energy@gov.ab.ca

Submitting Unit Values

- The 2017 unit value submission document is available through the department's Electronic Transfer System (ETS) - Freehold Mineral Tax – Download Unit Values. It will list single well and multiple well production entities producing from freehold mineral titles where you have a declared interest. Refer to the Download Unit Value section of the FMT On-line Learning on our website ETS FMT Online Learning

- Petroleum default and industry submitted unit values have been split into three petroleum code categories:

Petroleum Rights Products:	
OIL - Heavy	density greater than or equal to 900 kilograms per cubic metre
OIL - Light-Medium	density less than 900 kilograms per cubic metre
Bitumen (BIT)	reported as crude Bitumen production

- Please note that the unit value product codes will now display separately. **Unit Value submissions for these petroleum products will currently display for the 2017 tax year on ETS; however, values should not be submitted prior to January 1, 2018.**

- If the UV submission document does not include all of your production entities, refer to the Add Lessee section of the On-line Learning to establish a lessee role. The Department will only accept unit values submitted by a lessee who has declared an interest and has established a lessee role to the PE and titles. See Delete Lessee section of on-line learning to remove yourself from a PE/title.

- Record the unit values for the products and submit. See the Submit Unit Value section of the On-line Learning.

- A value of $0.00 is acceptable for PE/products where costs exceed revenues, or all gas was flared or used for lease fuel. Only submit a value of $0.00 if the unit value calculation is $0.00.

Do not submit $0.00 value if you have no interest in the PE.

Calculation of Unit Value for Petroleum and Gas Well Condensate

1. Unit Value ($) = $\dfrac{\text{Revenues (2)} - \text{Allowable Costs (3)}}{\text{Petroleum or Condensate Production (4)}}$

   Several Production Entities can be grouped at a battery to calculate a common unit value for all wells that contributed to the calculated revenues.

2. Revenues:
   Determine the gross revenue ($) from the sale of petroleum or gas well condensate from a production entity or group for the reporting period January 2017 to December 2017.

3. Allowable Costs:
   Determine the allowable costs ($) for the calendar year reporting period. Allowable costs are the actual costs incurred for transportation from the point of first measurement of the clean oil or gas well condensate to the first point of sale.

4. Production:
   Determine the total petroleum or condensate production (m^3) at the wellhead for the calendar year reporting period. The well volumes are those reported to the Alberta Energy Regulator (AER) through Petrinex.

5. Calculate the Unit Value ($ per m^3 of wellhead production):
   Deduct any allowable costs (3) from total gross revenues (2) and divide by petroleum or condensate production (4) to determine the wellhead unit value.

6. Record the unit value for Petroleum or CON of the production entities in the space on the Unit Value Submission spreadsheet.

Calculation of Unit Value for Field Gas or Solution Gas

A. Standard Gas Unit Value Calculation Method A (A): Using Crown Gas Royalty Information

Method A **(A)** is the Department's preferred method for calculating a gas and/or solution gas unit value. This standard method uses:

- Processed volumes(quantity/heat) from the Crown gas royalty invoice for the calendar year months
- Valuation pricing from the Crown gas royalty invoice for the calendar months
- Allocated operating costs for 2016
- Allocated custom processing fees for 2016
- Allocated capital costs for 2016
- Wellhead production volumes

Refer to the Gas Royalty Guidelines (2009) at
http://www.energy.alberta.ca/NG/LGP/Pages/Guidelines.aspx

Wells and production entities should be grouped by processing facility for gas and solution gas unit value calculations. Revenues, Costs and Production should be grouped at the same facility.

1. Unit Value ($) =

$$\frac{\text{Revenues } \mathbf{(2A)} - \text{Allowable Costs } \mathbf{(3A)}}{\text{Gas or Solution Gas Wellhead Production } \mathbf{(4A)}}$$

2. Revenues **(A)**:
   Determine revenues ($) for the production of gas and/or solution gas using the Crown Gas Royalty Detail invoice valuation prices for the calendar year reporting period. The valuation prices are multiplied by the Client Volumetric Totals processed (Quantity/Heat) for all product types (e.g. gas, ethane, propane, butane, pentanes and sulfur) from the production entity processed at each facility. Valuation prices already incorporate gas in-stream Facility Average Prices (FAP) and raw gas sales.

3. Allowable Costs **(A)**:
   Allowable costs for processing, gathering and compressing natural gas are actual allocated operating costs, capital costs and custom processing fees for 2016.

   Raw gas sold prior to processing and which is subsequently processed at a gas plant before delivery to a sales pipeline is valued at 80% of the gas reference price. Costs cannot be claimed for such raw gas sales. Raw gas sold and delivered to a sales pipeline without processing at a gas plant is valued at the Facility Average Price.

   Allowable Costs for 2016 use either:

   1. The production entities grouped by AER processing facility. This avoids the complexity of allocating costs at a well level. A unit value for the group is calculated using total revenues, costs and production for all of the streams in the group. Costs associated with the gathering, compression and processing of non-Alberta volumes and volumes purchased from a third party are not eligible. Costs incurred in the fractionation of proprietary NGL mix products from other gas plants into specification products are also ineligible. **or**

   2. Allocate costs for 2016 using the percentage of gas equivalent volumes (GEV) of the stream compared to the total GEV processed at the plant. Facilities that handle out of province volumes exclusively are not eligible for costs.

   3. Only use your WIO% share of allocated capital costs, not the total facility capital costs.

4. Production **(A)**:
   Determine the total gas or solution gas production (10^3m^3) at the wellhead using the calendar year reporting period for all wells that contributed to the calculated revenues **(2).** The volumes are those reported to the AER through Petrinex.

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

6. Record the unit value of the GAS or SOL for production entities on the UV submission spreadsheet.

B. Alternate Gas UV Calculation Method B (B): Actual Gross Revenues minus Crown Allowable Costs and Rates

1. Unit Value ($) = $\dfrac{\text{Actual Gross Revenues } \textbf{(2B)} \;-\; \text{Crown Allowable Costs } \textbf{(3A)}}{\text{Field Gas or Solution Gas Production } \textbf{(4A)}}$

2. Actual Gross Revenues:
   Determine the actual gross revenues ($) on the sale of gas or solution gas from each production entity for the calendar year reporting period. Include revenues from all by-products e.g. gas, ethane, propane, butane, pentanes and sulfur. Gas Valuation: Where freehold gas is commingled with other sources (Crown volumes, third party purchases, out of province volumes or other non-Crown volumes) before it is sold, the gross revenues attributable to freehold gas and by-product sales must be valued using the pooling concept. The revenue realized from the sale of all sources should be distributed proportionately to the ratio of volumes in the sales pool.

3. Crown Allowable Costs:
   Use the actual allocated costs for capital, operating and custom fees as in Standard Method A.

C. Alternate Gas UV Calculation Method C (C): Actual Gross Revenues minus Actual Allowable Costs

1. Unit Value ($) = $\dfrac{\text{Actual Gross Revenues } \textbf{(2C)} \;-\; \text{Actual Allowable Costs } \textbf{(3C)}}{\text{Field Gas or Solution Gas Production } \textbf{(4A)}}$

2. Actual Revenues:
   Determine gross revenues ($) on the sale of gas or solution gas from each production entity for the calendar year reporting period. Include revenues from all by-products e.g. gas, ethane, propane, butane, pentanes and sulfur. Gas Valuation: Where freehold gas is commingled with other sources (Crown volumes, third party purchases, out of province volumes or other non-Crown volumes) before it is sold, the gross revenues attributable to freehold gas and by-product sales must be valued using the pooling concept. The revenue realized from the sale of all sources should be distributed proportionately to the ratio of volumes in the sales pool.

3. Actual Allowable Costs:
   Determine allowable costs of the production ($) using the calendar year reporting period. Allowable costs are the actual custom processing fees or capital and operating costs incurred for, gathering, compressing, processing field gas or solution gas from the production entity. Allocate 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.

Flared or Lease Fuel Gas

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

2. The unit value will be $0.00 when the total volume of the gas produced in the calendar year reporting period has been flared or used as lease fuel as there are no revenues or deemed sales.

3. When only a portion of the gas produced was flared or used as lease fuel and the remaining portion was sold, the sales portion revenues are used in the unit value calculation. Dividing the revenues by the total production will result in a lower unit value. This will compensate for the portion of the gas flared or used as lease fuel.

4. Record the unit value for the production entities on the submission document.

Injected Gas

Injection of Taxable Gas or Products; a unit value is required for production entities when all or part of the production was injected.

All operating and capital costs for gathering, compressing and processing of production, whether sold or re-injected, are considered to be allowable costs. Allowable costs are recognized before any Crown Enhanced Oil Recovery (EOR) recapture adjustments. For companies that extract Capital and Custom Processing costs from the Capital Cost Recapture Summary and Custom Processing Fee Recapture Summary portion of the Crown Gas Royalty Invoice, the costs prior to EOR – Recapture should be used.

1. If all gas and liquids from the production entity are injected into the same field and pool where they were originally produced, there is no change in ownership and no revenue is recognized. The resulting unit value is $0.00.

2. If gas and liquids are injected into a different field or pool than where they were originally produced, the gas and products injected are considered to undergo a change in ownership, are deemed sold and are taxable. Revenue is determined similar to actual sales transactions.

3. When part of the gas and liquids production is sold and part is injected into the same field and pool, revenue is recognized only on the gas and liquids sold.

   When part of the gas and liquids production is injected into the same field and pool and part is injected into a different field or pool, the latter volumes are deemed to be sold and revenue is recognized.

   To ensure that revenue for products injected into the same field and pool is not recognized, companies using invoice client volumes in revenue calculations should reduce the relevant Crown Royalty (CR) charge type volumes by the related Injection Credit (IC) charge type volumes. Companies should retain documentation to substantiate the sources of the Injection Credit (IC) charge type volumes.

4. When part of the gas and liquids production is sold and part is injected into a different field or pool, revenue is recognized on all of the gas and liquids, whether sold or injected.

New Wells, Significant Production or Capital Changes

Unit values should be calculated over the balance of the reporting period when a new well starts production during the reporting period. Use the same calculation method as in Gas Unit Value Calculation Method (revenue and allowable costs).

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

- For the reporting period use July 2017 – December 2017 (6 months instead of 12)
- For the revenue use the Valuation price, by product, using Client Volumetric Totals (Quantity/Heat).
- For allowable costs use an estimated portion of current year's allowable capital and operating costs for the reporting period and/or
- Actual custom fees for July 2017 – December 2017 for volumes.
- Use production volumes for July 2017 –December 2017.

To calculate a UV for wells that start production during the taxation year, use the actual production volumes and estimated revenue and allowable cost estimates for the balance of the taxation year.

The next year's unit value calculation will follow the standard reporting period and methodology used by your company. Some of the same information will be re-used in the next year's unit value calculations.

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

Prior Period UV Adjustments, Amendments and Audits

Adjustments for Prior Period UV submissions

Production, revenue, operating cost, capital cost and custom processing fee changes identified after a tax year unit value filing deadline can be included as adjustments to subsequent years' unit value filings as prior year adjustments (PPA).
Include PPA for all non-statute barred years in your next unit value submission. e.g. Include any changes of the components of your original 2014, 2015 or 2016 tax year unit value calculation in the calculation of your 2017 unit value. Identify each PPA year and component separately. Detailed documentation of any prior period adjustments must be kept for audit purposes. For material adjustments, approval must be obtained from the department.

Amendments

To have any new or corrected information amended, contact Freehold Mineral Tax. Amendments can be filed for all non-statute barred tax years.

Notice of Objection

A notice of objection to the tax assessment for the 2017 tax year may be submitted. The requirements include a written notification and copies of all supporting information be submitted to the Minister as follows:

An objection to tax payable on a tax statement, other than a new corrected statement, shall be made on August 15^{th} in the year following the taxation year of which the objection is made, **or**

An objection to tax payable on a new statement or a corrected statement may be made within 90 days after the date of issue shown on the new or corrected tax statement.

Audits

All unit tax calculations are subject to audit by the Department's Compliance and Assurance Branch. Records of the production, revenue and costs of 2017 Freehold production entities can be reviewed until December 31, 2022 and must be made available within 30 days of request. The department may revise the original tax or may recommend an adjustment to the next year's unit value calculation.