ALBERTA MODERNIZED ROYALTY FRAMEWORK GUIDELINES

Principles and Procedures

Version 1.1

January 1, 2017

STATUS	VERSION	DATE (yyyy-mm-dd)	AUTHOR	DESCRIPTION
Final	1.0	2018-12-07	Katherine Clement	Final copy posted to Alberta Energy website
Final	1.1	2019-01-10	Katherine Clement	Update to section 7 and 7.1 regarding actual cost amendments and the removal of cost estimates. Update to section 7.5 regarding penalty effective date.

1. ALBERTA MODERNIZED ROYALTY FRAMEWORK GUIDELINES OVERVIEW

1.1 Introduction

The Modernized Royalty Framework (MRF) Guidelines (the guidelines) provide an understanding of the general application and principles involved in assessing the Drilling and Completion Cost Allowance (C*) and Alberta's Crown royalty share of crude oil, gas, natural gas liquids (NGLs) and non-project crude bitumen wells (the hydrocarbons) produced from lands under a Crown lease.

1.2 Modernized Royalty Framework

MRF applies to the hydrocarbons produced by wells spud or re-entered on or after January 1, 2017. MRF partially emulates a revenue minus cost royalty structure across all hydrocarbons. The Drilling and Completion Cost Allowance (C*), based on average industry drilling and completion costs, is a proxy for well costs. It determines the allowable revenue after which individual well sites begin paying Post C* royalty rates.

C* is calculated at the licence level. Each month the well produces a hydrocarbon, its revenue is valued using the respective hydrocarbon par/reference price. In accordance with the revenue minus cost structure, the total monthly revenue is used to draw down the C* until the C* Remaining is zero. A company will pay a flat royalty of 5% on a well's initial production until the well's cumulative revenue, from all hydrocarbon products, equals C*. Afterwards, the company will pay Post C* royalty rates that vary depending on the hydrocarbon, production levels and par/reference prices.

Two new programs were also introduced under MRF: the Enhanced Hydrocarbon Recovery Program (EHRP) and the Emerging Resources Program (ERP). More information regarding these programs is available on the Alberta Energy website https://www.energy.alberta.ca/AU/Royalties/Pages/default.aspx.

1.3 Early Opted-In Wells

Alberta Energy was accepting applications for wells to opt-in early to MRF. An approved opted-in well has a spud date on or after July 13, 2016 and on or before December 31, 2016. Re-entered wells are not eligible for early opt-in.

Wells spud during the early opt-in period that did not submit an eligible well application or did not meet the criteria will continue to operate under the Alberta Royalty Framework (ARF) until December 31, 2026, unless otherwise qualified through re-entry.

1.4 Oil Sands Wells

MRF will not impact royalties on production from an Oil Sands Royalty Project well or a well that was previously part of an Oil Sands Royalty Project, under the Oil Sands Royalty Regulation, 2009.

1.5 Alberta Royalty Framework

Wells spud before January 1, 2017, unless a MRF early opt-in well, will continue to operate under the Alberta Royalty Framework (ARF) until December 31, 2026, at which point all wells will transition to MRF Post C* royalty rates. For further information on ARF please refer to the Alberta Petroleum Royalty Guidelines located in the Oil section of the Alberta Energy website https://www.energy.alberta.ca/Oil/LGP/Pages/Guidelines.aspx and the Alberta Natural Gas Royalty Guidelines located in the Natural Gas section of the Alberta Energy website https://www.energy.alberta.ca/NG/LGP/Pages/Guidelines.aspx.

ARF wells that are re-entered may be eligible for MRF as stated in Section 2.2 Re-entry C*.

1.6 Authority

The MRF guidelines reflect the policies and procedures set in place to convey the legislative changes established by the *Mines and Minerals Act* (the Act), the Natural Gas Royalty Regulation, 2017 (the Gas Regulations) and the Petroleum Royalty Regulation, 2017 (the Oil Regulations) as of January 1, 2017. If a conflict should arise among the aforementioned legislation and the Alberta Modernized Royalty Guidelines, 2017, the Act and the Regulations will prevail.

1.7 Maintenance and Distribution

The MRF guidelines are updated when changes are made to the business rules. Alberta Energy often conducts presentations and/or training sessions with petroleum and natural gas industry groups (Industry) such as the Canadian Association of Petroleum Producers (CAPP), Small Explorers and Producers Association of Canada (SEPAC), and the Canadian Association of Petroleum Production Accountants (CAPPA), whenever major changes are made to the business rules. Alberta Energy periodically updates the guidelines to incorporate relevant policy or legislation changes.

The guidelines are available to royalty clients and other persons directly affected by the administration of Alberta Crown natural gas and petroleum royalties. Information Letters, Information Bulletins, and the guidelines are available on Alberta Energy's internet site at http://www.energy.alberta.ca.

1.7.1 Information Letters

Information Letters are sent to royalty clients who subscribe to the electronic delivery. These letters provide notification of:

- Reference prices, par prices, and other Crown oil/natural gas royalty factors
- Legislation and policy changes
- Interpretation and other information relevant to Crown royalty programs

1.7.2 Information Bulletins

Information Bulletins are sent to royalty clients who subscribe to the electronic delivery. These bulletins provide notification of:

- Business principle and procedure changes
- Filing dates, reminders, and interest rates
- General information relating to the ongoing administration of Crown royalty

2. DRILLING AND COMPLETION COST ALLOWANCE (C*)

The calculation of C* is the same for all wells, regardless of what hydrocarbon the well produces. When a MRF well is drilled, the well's true vertical depth (TVD), total lateral length (TLL), and total proppant placed (TPP) are entered into the Drilling and Completion Cost Allowance formula to calculate the C* value for the well. If any of these data elements are not provided, that element will default to zero and C* will be calculated based on that value. If the TVD is not provided C* cannot be calculated and C* will default to zero until the data is received. Calculations are rolled up to the licence level.

Please note that throughout this document there are numerical examples that do not necessarily reflect the reporting standards and significant decimal place requirements.

2.1 New Well C* Calculation

There are two formulas for calculating C* depending on the TVD of a well:

If TVD ≤ 2000m

C* = ACCI *((1170*(TVD-249)) + (Y*800*TLL) + (0.6*TVDa*TPPe))

If TVD > 2000m

C* = ACCI *((1170*(TVD-249)) + (3120*(TVD-2000)) + (Y*800*TLL) + (0.6*TVDa*TPPe))

Table 1

Acronym	Name	Description / Comment
ACCI	Alberta Capital Cost Index	This is prescribed by Alberta Energy to capture the changes in drilling and completion costs over time. It is calculated annually based on drilling and completion cost submissions made by Industry and can change by a maximum of plus or minus 5% from year to year. For the 2017 and 2018 calendar years the ACCI will be set to 1.00.
TVD	True Vertical Depth	When calculating the C* for a multi-leg well, the deepest TVD (TVDmax) is used. This data is based on the directional drilling surveys submitted to the Alberta Energy Regulator (AER). If TVD is equal to or less than 249m, then TVD – 249 will equal 0.
Y	Y Factor	Linear factor for multi-leg wells. It is determined based on the following formula: Y = 1.39 – 0.04*(TMD/TVDa) if the ratio of TMD/TVDa is less than 10, Y defaults to 1 if Y is calculated as less than 0.24, Y defaults to 0.24
TVDa	Average True Vertical Depth	Sum of the TVDs of all the legs in a well, divided by the number of legs. TVDa equals TVD when there is only one well event in the licence.
TMD	Total Measured Depth	Calculated by using the measured depth (MD) of the well and adding the length of any legs in the well measured from the end of the leg back to the first unique kickoff point (KOP) for that leg.
TLL	Total Lateral Length	Calculated by subtracting TVDmax, which is the deepest TVD of all legs, from the TMD of the well. TLL = (TMD – TVDmax)

<table>
<tr>
<td>TPPe</td>
<td>Total Proppant Placed Equivalent</td>
<td>Quantity of proppant placed (tonnes/m^3) times the equivalency factor for specific proppant types as per the table below:

<table>
<tr><th>Type of Proppant</th><th>Equivalency Factor</th></tr>
<tr><td>Sand (tonnes): naturally occurring unconsolidated sedimentary mineral material</td><td>1</td></tr>
<tr><td>Coated Sand (tonnes): sand that is treated with a permanent coating that improves its baseline conductivity by at least 50 per cent, compared to the baseline conductivity of the same uncoated sand, under the same stress conditions. This conductivity enhancement must be in accordance with ISO 135503-5 or its equivalent. The department may request independent laboratory tests as evidence of eligibility</td><td>1.5</td></tr>
<tr><td>Engineered/Manufactured (tonnes): a manufactured product</td><td>2.5</td></tr>
<tr><td>Acid (m^3) = Acid concentration * 10
7.5% concentration
15% concentration
28% concentration</td><td>
0.75
1.5
2.8</td></tr>
</table>

All carrier fluids and additives are not used in calculating the TPPe with the exceptions of when an acid only fracture occurs. In this case, acid as the carrier fluid cannot be used in combination with any other proppant types. Industry must apply to the DOE to receive approval for acid fractures, see <u>Section 2.5.1.</u></td>
</tr>
</table>

Single Well C* Calculation Example:

A new well was spud June 15, 2017 and has the following specifications:

	2017			
Event	TVD	TLL	TMD	TPP
00	4724m	1486m	6210m	965t

TPP is engineered sand

Calculate TLL

TLL = TMD – TVDmax
TLL = 6210 – 4724
TLL = 1486m

Calculate Y

Y = 1.39 – 0.04*(TMD/TVDa)
Y = 1.39 – 0.04*(6210/4724)
Y = 1.39 – 0.04*(1.314563929)
Y = 1.00
Based on the Y factor rules, when TMD/TVD is less than 10, Y defaults to 1.00

Calculate Proppant Equivalency using the TPPe chart in Table 1

TPPe = 965 * 2.5
TPPe = 2412.5t

Calculate C*

TVD >2000 formula

C* = ACCI *((1170*(TVD - 249)) + (3120*(TVD - 2000)) + (Y*800*TLL) + (0.6*TVDa*TPPe))
C* = 1.0 *((1170*(4724 - 249)) + (3120*(4724 - 2000) + (1.00*800*1486) + (0.6*4724*2412.5))
C* = 5,235,750 + 8,498,880 + 1,188,800 + 6,837,990
C* = $21,761,420.00

2.2 Re-Entry C*

Activities that occur within one year of the earliest producing date of a well are considered part of the initial activity. Activities that occur after the initial activity period has ended are considered re-entry activities.

Re-entry is defined as all drilling or fracturing operations in a well that results in a change to TVD, TLL or TPPe, which occurs after the initial activity period and/or one year from the previous re-entry activity.

2.2.1 MRF Well

When a MRF well is re-entered after the initial activity period it will be awarded an Incremental C*. The Incremental C* will be added to any C* balance that is still remaining unless the well's cumulative revenue has met or exceeded its C* prior to re-entry. The production from all the well events from the re-entered date forward will contribute to the drawdown of the well's C*.

2.2.2 ARF Well

When an ARF well is re-entered after January 1, 2017 and has previously produced hydrocarbons a year or more prior to the re-entry activity, the well is subject to MRF and a C* is calculated based on that activity. The well will switch from ARF to MRF until the Incremental C* is drawn down to zero. Once the C* is completely drawn down, the well will revert back to ARF until December 31, 2026 at which point all wells will be under MRF. An ARF well that is re-entered after January 1, 2017 and has never produced will follow the ARF regime. The well must exceed the initial activity period, one year from the month it first produces oil, gas or NGLs, and perform another re-entry activity to receive an incremental C* value.

If the well is receiving benefit under ARF royalty programs, those benefits will run concurrently with C*, therefore they will continue to decrease while the well is subject to C* royalty rates. Once the cumulative revenue based on hydrocarbon production from the well equals its Incremental C*, the well will revert back to ARF and will continue to receive any benefit remaining under the ARF royalty programs.

2.2.3 Re-entry C* Calculation

When a well has been re-entered an Incremental C* is calculated based on the corresponding formula for the specific re-entry activity. The three different re-entry formulas are listed in the following sub-sections.

2.2.3.1 *Lengthen Only*

When a well re-entry results in lengthening only, the Incremental C* will be calculated based on the below formula:

C* = ACCI *(1000*TLLi)

TLLi is the incremental total lateral length. It is the difference between the TLL (described in Table 1) of the new drilling activity where lengthening has occurred and the TLL prior to the new drilling activity (New TLL – Prior TLL).

Lengthen Only Example:

A single leg horizontal well is lengthened in 2018 with the following attributes:

	2017 Attributes				**2018 Attributes**			
Event	TVD_{max}	TMD	TLL	TPP	TVD_{max}	TMD	TLL	TPP
00	3215m	4462m	1247m	947t	3215m	5398m	2183m	947t

Note: 2018 ACCI is equal to 1.00

Calculate TLL for 2017 and 2018 as described in Table 1

TLL (2017) = TMD – TVDmax
TLL (2017) = 4462 – 3215
TLL (2017) = 1247m

TLL (2018) = TMD – TVDmax
TLL (2018) = 5398 - 3215
TLL (2018) = 2183m

Calculate TLLi

TLLi = New TLL – Prior TLL
TLLi = 2183 - 1247
TLLi = 936m

Calculate C*

C* = ACCI *(1000*TLLi)
C* = 1.00 *(1000*936)
C* = $936,000.00

2.2.3.2 *Fracture Only*

When a well re-entry results in fracturing only, the Incremental C* will be calculated based on the below formula. The minimum proppant equivalency added, as per the TPPe chart in Table 1, must be met; 10 tonnes equivalent for a vertical well and 50 tonnes equivalent for a horizontal well.

C* = ACCI *(1.5*(0.6*TVDp*TPPi) + 150,000)

TVDp is the average of the true vertical depths of the legs where incremental proppant has been placed.

TPPi is the incremental proppant equivalency placed. The incremental proppant is the additional amount of equivalent proppant placed since the last fracture activity.

Fracture Only Example:

A multi-leg horizontal well that has previously produced in 2008 is fractured again in 2017 using coated sand.

	2008 Attributes			**2017 Attributes**		
Event	TVD	TLL	TPP	TVD	TLL	TPP
00	671m	1110m	312t	671m	1110m	0
02	850m	1121m	451t	850m	1121m	621t
03	1238m	1201m	241t	1238m	1201m	924t
04	1239m	1052m	642t	1239m	1052m	0

Note: 2017 ACCI is equal to 1.00

Calculate TVDp

TVDp = (850 + 1238)/2
TVDp = 1044m

Calculate TPPi using the incremental 2017 TPP and the TPPe chart in Table 1 to calculate the coated sand equivalency

TPPi = (621 + 924)*1.5
TPPi = 2317.5t

Calculate C*

C* = ACCI *(1.5*(0.6*TVDp*TPPi) + 150,000)
C* = 1.00 *(1.5*(0.6*1044*2317.5) + 150,000)
C* = $2,327,523.00

2.2.3.3 *Deepening Only or Combination of Lengthening, Deepening and/or Fracturing (Incremental C*)*

When a well re-entry results in deepening only or any combination of lengthening, deepening, and fracturing, the Incremental C* will be calculated based on the below formula. To be eligible for the proppant portion of the formula the minimum proppant equivalency added, as per the TPPe chart in Table 1, must be met; 10 tonnes equivalent for a vertical well and 50 tonnes equivalent for a horizontal well.

Incremental C* = C* New - C* Prime

Where:

- C* New is the C* value calculated using the formula for a new well as seen in Section 2.1, but where TVD, TVDa, TPPe, TLL and Y are measured or calculated for the well after the re-entry and the ACCI is the ACCI for the year of the re-entry.
- C* Prime is the C* value calculated using the formula for a new well as seen in Section 2.1, but where TVD, TVDa, TPPe, TLL and Y are measured or calculated for the well immediately before the re-entry and the ACCI is the ACCI for the year of the re-entry.

Incremental C* Example:

A horizontal well spud in 2010 has been re-entered through new drilling in 2017 and fractured with sand.

	2010 Attributes				**2017 Attributes**			
Event	TVD	TLL	TPP	MD	TVD	TLL	TPP	MD
00	671m	1148m	0t	1819m	671m	1148m	0t	1819m
02					850m	478m	621t	2168m

Note: 2017 ACCI is equal to 1.00 and the unique KOP for the 02 event is 840.0m.

Please refer to Table 1 for the definitions of the specific variables used in the formulas.

Calculate C* Prime using the 2010 attributes and the 2017 ACCI

Y = 1.39 – 0.04*(TMD/TVDa)
Y = 1.39 – 0.04*(1819/671)
Y = 1.39 – 0.04*(2.710879285)
Y = 1.00
Based on the Y factor rules, when TMD/TVDa is less than 10, Y defaults to 1.00.

TLL = TMD – TVDmax
TLL = 1819 – 671
TLL = 1148m

TPPe = 0t

TVDa = 671m

C* = ACCI *((1170*(TVD - 249)) + (Y*800*TLL) + (0.6*TVDa*TPPe))
C* = 1.00 *(493,740.00 + 918,400.00 + 0.00)
C* = $1,412,140.00

Calculate C* New using the 2017 attributes and 2017 ACCI

TMD = 1819 + (2168 – KOP)
TMD = 1819 + (2168 – 840.0)
TMD = 3147m

TLL = TMD – TVDmax
TLL = 3147 – 850
TLL = 2297m

TVDa = (671 + 850)/2
TVDa = 760.5m

Y = 1.39 – 0.04*(TMD/TVDa)
Y = 1.39 – 0.04*(3147/760.5)
Y = 1.39 – 0.04*(4.138067061)
Y = 1.00
Based on the Y factor rules, when TMD/TVDa is less than 10, Y defaults to 1.00.

TPPe = 621*1
TPPe = 621t

C* = ACCI*((1170*(TVD-249)) + (Y*800*TLL) + (0.6*TVDa*TPPe))
C* = 1.00*((1170*(850-249)) + (1.00*800*2297) + (0.6*760.5*621))
C* = 1.00*(703,170.00 + 1,837,600.00 + 283,362.30)
C* = $2,824,132.30

Calculate the Incremental C*

Incremental C* = $2,824,132.30 - $1,412,140.00
Incremental C* = $1,411,992.30

2.3 Abandoned Well Event

Drilled well events that have an abandoned status and have never produced are excluded from the well's C* calculation. There is no change to the original C* calculation if a well event has produced and is later changed to an abandoned status.

If a drilled well event's status is switched from an abandoned to an active status the well event will then contribute to the C* value as long as it qualifies under MRF. If all well events within a well are abandoned, the C* is reduced to zero and is no longer available, even upon re-entry. If any of the well events within a well change their status back to active without new drilling the well's royalty will be calculated using Post C* rates.

2.4 Abandoned Licence

If a MRF licence is cancelled or abandoned as administered by the Alberta Energy Regulator, an operator has six months from the abandoned status date to report production. After this six months has passed the C* will be reduced to zero. MRF wells coming back on to production, without lengthening, deepening or fracturing will be subject to a Post C* rate.

If an abandoned licence is re-entered a new C* will be calculated based on the new re-entry activities, please refer back to Section 2.2 for re-entry qualifications.

2.5 Written Request for Specific C* Activities

A letter of request to Alberta Energy (Energy.MRFInquiries@gov.ab.ca) is required to receive a C* for the activities of an acid only fracture and wells where more than nine well events have been completed. The letter details are outlined in the following sections. If a request is not received for such activities, additional C* benefit will not be calculated.

2.5.1 Acid Only Fracture

Acid only fractures occur when acid is used to fracture a well and no proppant is used in combination with it. For an acid only fracture to be eligible for a MRF re-entry activity the minimum proppant equivalency added, as per the TPPe chart in Table 1, must be met; 10 tonnes equivalent for a vertical well and 50 tonnes equivalent for a horizontal well.

While there is no formal application for submitting an acid only fracture to Alberta Energy for approval, the below list is a general set of information that should be included in the letter of request. The letter can be emailed to Energy.MRFInquiries@gov.ab.ca.

- Licence and Unique Well Identifier (UWI)
- Spud Date
- Service company workover/completion reports, including activity dates, acid name (formula), acid concentration, and total volumes

2.5.2 Wells with Greater than Nine Well Events

C* will automatically be calculated for wells with up to nine well events based on the information that Alberta Energy receives from the AER's DDS (Digital Data System). When a well has more than nine well events, the additional well information cannot be collected by Alberta Energy. Once industry has submitted the appropriate data to the AER a C* calculation request can be sent to Alberta Energy (Energy.MRFInquiries@gov.ab.ca).

3. DETERMINING REVENUE TO DRAW DOWN C*

C* is drawn down each month according to the revenue minus cost structure of MRF. Alberta Energy will determine a well's monthly revenue by multiplying volumes of all the hydrocarbons produced, including test production, by their respective par/reference prices as published in the Information Letters available on the Alberta Energy website. The formula for calculating a well's monthly revenue for each hydrocarbon is as follows:

Revenue = Production * Par Price

The total monthly revenue is the sum of each individual hydrocarbon's revenue. The cumulative revenue drawdown is the sum of each month's total revenue. C* Remaining is the difference between the calculated C* and the cumulative revenue. While C* Remaining is greater than zero, the well pays a flat 5% royalty rate. Once C* Remaining reaches zero, the well will pay Post C* royalty rates (See Sections 5 and 6). It is possible for C* Remaining to reach zero mid-month. This will result in multiple royalty rates (i.e. moving from C* to Post C*) and is described further in Section 4.2. The table below provides clarity for which volume measurement points will be used to calculate revenue based on the commodity produced.

Conventional Oil	Wellhead Production
Condensate	
Natural Gas – ISC (methane, ethane, ..)	Allocated Volumes
Natural Gas by-products – liquids mix and spec (propane, butanes and pentanes plus)	
Sulphur	

C* Drawdown Example:

A well with a total C* of $1,578,900.00 has the following in their initial month of production:

Product	Production/Allocated Volumes	Par/Reference Price
Light Oil	240.0m^3	$389.61/$m^3$
Natural Gas	83GJ	$2.20/GJ
Propane Mix	15.0m^3	$68.91/$m^3$
Condensate	120.0m^3	$360.00/$m^3$

Calculate monthly revenue for each hydrocarbon

Light Oil = 240.0m^3 * $389.61/$m^3$ = $93,506.40
Natural Gas = 83GJ * $2.20/GJ = $182.60
Propane Mix = 15.0m^3 * $68.91/$m^3$ = $1,033.65
Condensate = 120.0m^3 * $360.00/$m^3$ = $43,200.00

Calculate total revenue for the month by adding all hydrocarbon revenues

Total Revenue = $93,506.40 + $182.60 + $1,033.65 + $43,200.00
Total Revenue = $137,922.65

If more than one month of production has occurred, add the total revenues from each month to obtain the cumulative revenue.

Calculate C* Remaining

C* Remaining = C* - Cumulative Revenue
C* Remaining = $1,578,900.00 – $137,922.65
C* Remaining = $1,440,977.35
Since the C* Remaining is greater than zero, the royalty rate for this month is 5%.

4. DETERMINING AND VALUING THE CROWN ROYALTY RATE

4.1 C* Royalty Rate Calculation

All products produced by a well will pay a flat royalty rate of 5% as long as the cumulative revenue of a well is less than the calculated C* (i.e. C* Remaining is greater than zero). For MRF wells where the system is unable to calculate a C* due to missing information, Post C* rates will be applied. Once the information has been received, C* will be calculated and recognized to determine royalty rates retroactive to the first month of eligible production.

4.2 Post C* Royalty Rate Calculation

Post C* royalty rates are applied when revenue drawdown from a licence is equal to or greater than its C* (i.e. C* is capped out). C* can cap out mid-month when the cumulative revenue equals C* using only a portion of the wells monthly production. The remaining volumes not contributing to the cap will have their royalty calculated using Post C* royalty rates. As volumetric totals are reported monthly rather than daily, the cap will be reported as being reached in a specific month and not on a specific day. If a well event's royalty is calculated using multiple royalty rates due to a C*mid-month cap out, oil volumes are applied to the revenue draw down first. Any remaining volumes in excess of the cap will have their royalty calculated at their respective rates (i.e. Post C*, ARF, NWRR, etc.). In the following month when gas and NGL's are reported, the oil volumes will be amended and all hydrocarbon volumes are retro-actively and equally prorated to meet the revenue cap. Post C* rates do not apply to ARF wells that are re-entered. When a re-entered ARF well draws down its C* mid-month, the remaining volumes that did not contribute to the drawdown of C* will have their royalty calculated using ARF royalty rates.

The Post C* royalty rate (R%) for a month is the amount calculated in accordance with the formula for each hydrocarbon:

$$R\% = r_p + r_q$$

The price component (r_p) is the percentage rate based on the par/reference price for each hydrocarbon. See Sections 5 and 6 for commodity specific price rate formulas.

The quantity component (r_q) reflects the well's productivity in comparison to a prescribed Maturity Threshold (MT). When production is above MT, the r_q is zero. When production declines below the MT, a formula (described in Sections 5 & 6) is used to calculate a negative r_q.

Whether a well's production is above or below MT is determined at the wellhead by combining all hydrocarbons produced into either Gas Equivalent Volumes (GEV) or Oil Equivalent Volumes (OEV). To determine the GEV and OEV of a well, the combined monthly oil, condensate and raw natural gas production are converted based on a conversion factor of 1.7811. The total equivalent volumes are then compared against the maturity threshold.

The prescribed maturity thresholds are:

- Gas equivalent volumes (GEV) = 345.5 10^3m^3
- Oil equivalent volumes (OEV) = 194.0 m^3

Maturity Threshold Example:

A well produces the following in the month of January:

Product	Wellhead Production	Raw Gas Production	GEV 10^3m^3	OEV m^3
Oil	125.0 m^3		222.6 10^3m^3 *(=125.0 m^3*1.7811)*	125.0 m^3
Natural Gas		90.0 10^3m^3	90.0 10^3m^3	50.5 m^3 *(=90.0 10^3m^3/1.7811)*
Total			312.6 10^3m^3	175.5 m^3

With a GEV of less than 345.5 10^3m^3/month and an OEV of less than 194.0 m^3/month, the r_q will calculate to a negative number, thereby reducing the royalty rate.

5. OIL ROYALTY RATE CALCULATION

5.1 Royalty Rate for Oil

The oil royalty rate can range from a minimum 5% to a maximum 40%. A royalty rate of 5% will be applied to MRF oil wells that are in C*.

Wells that are in Post C* receive a royalty rate comprised of a price and quantity component as determined in the following sections.

Price Component

The price component of oil is determined by using the monthly oil par price (PP) based on density.

Table 2

Par Price ($/m³)	**r_p (%)**
PP ≤ 251.70	10%
251.70 < PP ≤ 409.02	[(PP – 251.70) * 0.00071 + 0.10000] * 100
409.02 < PP ≤ 723.64	[(PP – 409.02) * 0.00039 + 0.21170] * 100
723.64 < PP	[(PP – 723.64) * 0.00020 + 0.33440] * 100
Maximum	40%

Quantity Component

The total monthly production (Q) is the sum of oil, gas and condensate produced by the well events under a licence in oil equivalent volumes. This is used to calculate the quantity component of the R% formula. If Q in OEVs is less than the maturity threshold for oil (194.0 m^3), a maturity adjustment is calculated. If Q in OEVs is equal to or greater than the maturity threshold for oil, the maturity adjustment is zero.

Table 3

Quantity (m^3)	**r_q (%)**
194.0 ≤ Q	0%
Q < 194.0	[(Q – 194.0) * 0.001350] * 100

Oil Royalty Rate Example:

With a par price of $364.06/$m^3$ for light oil, the second row in Table 2 for the price component would be used:

r_p = [(PP – 251.70) * 0.00071 + 0.10000] * 100
= [(364.06 – 251.70) * 0.00071 + 0.10000] * 100
= 17.97756%

With a total monthly production of 146.0 m^3, the Q is less than the 194.0 m^3 maturity threshold for oil as described in Section 4.2; the second row in Table 3 for the quantity component would be used:

r_q = [(Q – 194.0) * 0.001350] * 100
= [(146 – 194.0) * 0.001350] * 100
= -6.48%

The R% for oil is calculated as follows:

R% = r_p + r_q
= 17.97756% + (-6.48%)
= 11.50%

6. GAS ROYALTY RATE CALCULATION

The royalty rate of 5% will be applied to gas and gas products for MRF wells that are in C*.

Wells that are in Post C* receive a royalty rate comprised of a price and quantity component as determined in the following sections.

6.1 Royalty Rate for Methane-ISC and Ethane-ISC, Ethane Mix and Spec

The royalty rate calculation for methane in-stream components (C1-IC), ethane in-stream components (C2-IC), ethane mix (C2-MX) and ethane spec (C2-SP) is comprised of a price component and a quantity component.

The minimum R% is 5%. The maximum R% is 36%.

Price Component

The price component of the royalty rate formula for ethane mix and spec is based on the respective monthly par price of ethane mix and spec. The royalty rate of methane and ethane ISCs is based on the monthly par price of gas.

Table 4

Par Price ($/GJ)	**r_p (%)**
PP ≤ 2.40	5%
2.40 < PP ≤ 3.00	[(PP – 2.40) * 0.06000 + 0.05000] * 100
3.00 < PP ≤ 6.75	[(PP – 3.00) * 0.04250 + 0.08600] * 100
6.75 < PP	[(PP – 6.75) * 0.02250 + 0.24538] * 100
Maximum	36%

Quantity Component

The total monthly production is the sum of oil, gas and condensate produced by the well events under the licence in gas equivalent volumes. This is used to calculate the quantity component of the R% formula. If Q in GEV is less than the maturity threshold for gas (345.5 10^3m^3), a maturity adjustment is calculated. If Q in GEV is equal to or greater than the maturity threshold for gas, the maturity adjustment is zero.

Table 5

Quantity (10^3m^3)	**r_q (%)**
Q ≥ 345.5	0%
Q < 345.5	[(Q – 345.5) * 0.0004937] * 100

Ethane-ISC (C2-IC) Royalty Rate Example:

With a par price of $3.20/10^3m^3 for ethane-ISC, the third row in Table 4 for the price component would be used:

$$
\begin{aligned}
r_p &= [(PP - 3.00) * 0.04250 + 0.08600] * 100 \\
&= [(3.20 - 3.00) * 0.04250 + 0.08600] * 100 \\
&= 9.45\%
\end{aligned}
$$

With a total monthly production of 100.0 10^3m^3 of gas and 50.0 m^3 of condensate, the GEV as described in Section 4.2 is calculated as follows:

$$
\begin{aligned}
Q\ (GEV) &= 100.0 + (50.0 * 1.7811) \\
&= 189.1\ 10^3m^3
\end{aligned}
$$

Since Q is less than the 345.5 10^3m^3 maturity threshold for gas as described in Section 4.2; the second row in Table 5 for the quantity component would be used:

$$
\begin{aligned}
r_q &= [(Q - 345.5) * 0.0004937] * 100 \\
&= [(189.1 - 345.5) * 0.0004937] * 100 \\
&= -7.72147\%
\end{aligned}
$$

The R% for ethane-ISC is calculated as follows:

$$
\begin{aligned}
R\% &= r_p + r_q \\
&= 9.45\% + (-7.72147\%) \\
&= 1.73\% \\
&= 5\% \text{ minimum rate used as described in Section 6.1}
\end{aligned}
$$

6.2 Royalty Rate for Propane-ISC, Propane Mix and Spec

The royalty rate calculation for propane in-stream components (C3-IC), propane spec (C3-SP) and propane mix (C3-MX) is comprised of a price component and quantity component.

The minimum R% is 5%. The maximum R% is 36%.

Price Component

The price component formula is based solely on the respective monthly liquid par prices for propane mix and spec. The royalty rate for propane-ISC is based on the respective monthly par price for propane mix (C3-MX).

Table 6

Par Price ($/m^3)	r_p (%)
PP ≤ 88.10	10%
88.10 < PP ≤ 143.16	[(PP – 88.10) * 0.00202 + 0.10000] * 100
143.16 < PP ≤ 253.28	[(PP – 143.16) * 0.00111 + 0.21122] * 100
253.28 < PP	[(PP – 253.28) * 0.00059 + 0.33347] * 100
Maximum	36%

Quantity Component

The total monthly production is the sum of oil, gas and condensate produced by the well events under the licence in oil equivalent volumes. This is used to calculate the quantity component of the R% formula. If Q in OEV is less than the maturity threshold for oil (194.0 m^3), a maturity adjustment is calculated. If Q in OEV is equal to or greater than the maturity threshold for oil, the maturity adjustment is zero.

Table 7

Quantity (m^3)	r_q (%)
Q ≥ 194.0	0%
Q < 194.0	[(Q – 194.0) * 0.001350] * 100

Propane Spec (C3-SP) Royalty Rate Example:

With a par price of $102.96/m^3 for propane spec (C3-SP), the second row in Table 6 for the price component would be used:

r_p = [(PP – 88.10) * 0.00202 + 0.10000] * 100
= [(102.96 – 88.10) * 0.00202 + 0.10000] * 100
= 13.00172%

With a total monthly production of 42.9 10^{3}m^3 of gas and 12.2 m^3 of condensate, the OEV as described in Section 4.2 is calculated as follows:

Q (OEV) = (42.9 / 1.7811) + 12.2
= 36.3 m^3

Since Q is less than the 194.0 m^3 maturity threshold for oil as described in Section 4.2; the second row in Table 7 for the quantity component would be used:

r_q = [(36.3 – 194.0) * 0.001350] * 100
= -21.2895%

The R% for propane spec is calculated as follows:

R% $= r_p + r_q$
= 13.00172% + (-21.2895%)
= -8.29%
= 5% minimum rate used as described in Section 6.2

6.3 Royalty Rate for Butanes-ISC, Butanes Mix and Spec

The royalty rate calculation for butanes in-stream components (C4-IC), butanes spec (C4-SP) and butanes mix (C4-MX) is comprised of a price component and quantity component.

The minimum R% is 5%. The maximum R% is 36%.

Price Component

The price component formula is based solely on the respective monthly liquid par prices for butanes mix and spec. The royalty rate for butanes-ISC is based on the respective monthly par price for butanes mix.

Table 8

Par Price ($/m³)	**r_p (%)**
PP ≤ 176.19	10%
176.19 < PP ≤ 286.31	[(PP – 176.19) * 0.00101 + 0.10000] * 100
286.31 < PP ≤ 506.55	[(PP – 286.31) * 0.00055 + 0.21122] * 100
506.55 < PP	[(PP – 506.55) * 0.00031 + 0.33235] * 100
Maximum	36%

Quantity Component

The total monthly production is the sum of oil, gas and condensate produced by the well events under the licence in oil equivalent volumes. This is used to calculate the quantity component of the R% formula. If Q in OEV is less than the maturity threshold for oil (194.0 m^3), a maturity adjustment is calculated. If Q in OEV is equal to or greater than the maturity threshold for oil, the maturity adjustment is zero.

Table 9

Quantity (m^3)	**r_q (%)**
Q ≥ 194.0	0
Q < 194.0	[(Q – 194.0) * 0.001350] * 100

Butanes Mix (C4-MX) Royalty Rate Example:

With a par price of $250.00/m^3 for butanes mix (C4-MX), the second row in Table 8 for the quantity component would be used:

$$
\begin{aligned}
r_p &= [(PP - 176.19) * 0.00101 + 0.10000] * 100 \\
&= [(250.00 - 176.19) * 0.00101 + 0.10000] * 100 \\
&= 17.45481\%
\end{aligned}
$$

With a total monthly production of 200.0 10^3m^3 of gas and 110.0 m^3 of condensate, the OEV as described in Section 4.2 is calculated as follows:

$$
\begin{aligned}
Q\ (OEV) &= (200.0 / 1.7811) + 110 \\
&= 222.3\ m^3
\end{aligned}
$$

Since Q is greater than the 194.0 m^3 maturity threshold for oil as described in Section 4.2; the first row in Table 9 for the quantity component would be used:

$$r_q = 0\%$$

The R% for butanes mix is calculated as follows:

$$
\begin{aligned}
R\% &= r_p + r_q \\
&= 17.45481\% + 0\% \\
&= 17.45\%
\end{aligned}
$$

6.4 Royalty Rate for Pentanes Plus-ISC, Pentanes Plus Mix and Spec

The royalty rate for pentanes plus in-stream components (C5+-IC), pentanes spec (C5-SP) and pentanes plus mix (C5-MX) is comprised of a price component and quantity component.

The minimum R% is 5%. The maximum R% is 40%.

Price Component

The price component formula of pentanes plus mix and spec is based on the respective monthly liquid par price of the pentanes plus mix and spec. The royalty rate of pentanes plus-ISC is based on the monthly liquid par price of the pentanes plus spec.

Table 10

Par Price ($\$/m^3$)	r_p (%)
PP ≤ 251.70	10%
251.70 < PP ≤ 409.02	[(PP – 251.70) * 0.00071 + 0.10000] * 100
409.02 < PP ≤ 723.64	[(PP – 409.02) * 0.00039 + 0.21170] * 100
723.64 < PP	[(PP – 723.64) * 0.00020 + 0.33440] * 100
Maximum	40%

Quantity Component

The total monthly production is the sum of oil, gas and condensate produced by the well events under the licence in oil equivalent volumes. This is used to calculate the quantity component (r_q) of the R% formula. If Q in OEV is less than the maturity threshold for oil (194.0 m^3), a maturity adjustment is calculated. If Q in OEV is equal to or greater than the maturity threshold for oil, the maturity adjustment is zero.

Table 11

Quantity (m^3)	r_q (%)
Q ≥ 194.0	0
Q < 194.0	[(Q – 194.0) * 0.001350] * 100

Pentanes Plus Spec (C5-SP) Royalty Rate Example:

With a par price of $1,200.00/$m^3$ for pentanes plus spec, the last row in Table 10 for the price component would be used:

r_p = [(PP – 723.64) * 0.00020 + 0.33440] * 100
= [(1200 – 723.64) * 0.00020 + 0.33440] * 100
= 42.97%
= 40% maximum rate used as described in Section 6.4

With a total monthly production of 346.0 10^3m^3 of gas, the OEV as described in Section 4.2, is calculated as follows:

Q (OEV) = 346.0 / 1.7811
= 194.3 m^3

Since Q is greater than 194.0 m^3 maturity threshold for oil as described in Section 4.2; the second row in Table 11 for the quantity component would be used:

r_q = 0%

The pentanes plus spec royalty rate for this production month is as follows:

$$\begin{aligned} R\%\% &= r_p + r_q \\ &= 40\% + 0\% \\ &= 40\% \end{aligned}$$

6.5 Royalty Rate for Condensate

The royalty rate for condensate is comprised of a price component and quantity component.

The minimum R% is 5%. The maximum R% is 40%.

Price Component

The price component formula for condensate (COND) is determined by the monthly liquid par price of pentanes plus spec.

Table 12

Par Price ($\$/m^3$)	**r_p (%)**
PP ≤ 251.70	10%
251.70 < PP ≤ 409.02	[(PP – 251.70) * 0.00071 + 0.10000] * 100
409.02 < PP ≤ 723.64	[(PP – 409.02) * 0.00039 + 0.21170] * 100
723.64 < PP	[(PP – 723.64) * 0.00020 + 0.33440] * 100
Maximum	40%

Quantity Component

The total monthly production is the sum of oil, gas and condensate produced by the well events under the licence in oil equivalent volumes. This is used to calculate the quantity component of the R% formula. If Q in OEV is less than the maturity threshold for oil (194.0 m^3), a maturity adjustment is calculated. If Q in OEV is equal to or greater than the maturity threshold for oil, the maturity adjustment is zero.

Table 13

Quantity (m^3)	**r_q (%)**
Q ≥ 194.0	0%
Q < 194.0	[(Q – 194.0) * 0.001350] * 100

Condensate Royalty Rate Example:

With a par price of $200.00/m^3 for pentanes plus spec, the first row in Table 12 for the price component would be used:

r_p = 10%

With a total monthly production of 100.0 10^3m^3 of gas and 50.0 m^3 of condensate, the OEV as described in Section 4.2 is calculated as follows:

$$Q\ (OEV) = (100.0 / 1.7811) + 50.0$$
$$= 106.1\ m^3$$

Since Q is less than 194.0 m^3 maturity threshold for oil as described in Section 4.2; the first row in Table 13 for the quantity component would be used:

$$r_q = [(Q – 194.0) * 0.001350] * 100$$
$$= [(106.1 – 194.0) * 0.001350] * 100$$
$$= -11.87\%$$

The R% for condensate is calculated as follows:

$$R\% = r_p + r_q$$
$$= 10\% + (-11.87\%)$$
$$= -1.87\%$$

= 5% minimum rate used as described in Section 6.5

6.6 Royalty Rate for Sulphur

The Crown royalty rate for sulphur (SUL) is 16.66667% for MRF eligible quantities. This remains unchanged from ARF.

6.7 Well Event Average Royalty Rate (WEARR)

Gas royalty rates continue to be assessed using the WEARR based on the in-stream component breakdown of the gas at the trigger facility and the royalty rate of each in-stream component. Under MRF, methane, ethane, propane, butanes, and pentanes plus royalty rates are all formula based.

For a Single Well Production Entity (SWPE), WEARR is calculated using the following formula:

WEARR = R%C1-IC * ISC HeatC1-IC + R%C2-IC * ISC HeatC2-IC +
R%C3-IC * ISC HeatC3-IC + R%C4-IC * ISC HeatC4-IC +
R%C5+-IC * ISC HeatC5+-IC

where:

R%C1-IC, R%C2-IC R%C3-IC, R%C4-IC and R%C5+-IC are the product royalty rates calculated for the well event using the MRF formulas for each product,

and

ISC HeatC1-IC, ISC HeatC2-IC, ISC HeatC3-IC, ISC HeatC4-IC and ISC HeatC5+-IC are the ISC factors of the gas dispositions at the trigger facility weighted by total heat of each stream.

For a gas stream that is from a Multi-Well Production Entity (MWPE), the royalty rate will be a weighted average using each well event's gas production.

Multi-well streams that consist of production from one or more MRF, and one or more ARF eligible well events are assessed using a blended royalty rate comprising of the individual WEARR calculated for each well event, weighted by the individual well event's gas production.

The WEARR is calculated using the following formula:

WEARR (MWPE) = (WEARR1*Q1 + WEARR2*Q2 + … + WEARRn*Qn) divided by (Q1 + Q2 + … + Qn)

where:

WEARR1, WEARR2, … WEARRn are the individual WEARR of the well events in the MWPE Q1, Q2, … Qn are the gas production of the well events in the MWPE.

6.7.1 WEARR Example

The following illustrates the determination and calculation of WEARR for a single well event under MRF.

Price Component

Under MRF, the r_p for all royalty liable ISC's are formula based, using par/reference price as determined and published by the Department for a given month, as follows:

Table 14

ISC	Par Price Used
C1-IC	C1-IC
C2-IC	C2-IC
C3-IC	C3-MX
C4-IC	C4-MX
C5+-IC	C5-SP

For a production month with the following par prices:

Methane ISC PP: $3.20/GJ
Ethane ISC PP: $3.20/GJ
Propane Mix PP: $78.96/m^3
Butane Mix PP: $460.85/m^3
Pentane Plus Spec PP: $864.74/m^3

The price component for each ISC is calculated using its respective par price and formula:

Methane and Ethane ISC

Table 15

Par Price ($/GJ)	r_p (%)
PP ≤ 2.40	5%
2.40 < PP ≤ 3.00	[(PP – 2.40) * 0.0600 + 0.05000] * 100
3.00 < PP ≤ 6.75	[(PP – 3.00) * 0.04250 + 0.08600] * 100
6.75 < PP	[(PP – 6.75) * 0.02250 + 0.24538] * 100
Maximum	36%

With a methane and ethane ISC price of $3.20/GJ, the third row in Table 15 for the price component would be used:

$$r_p \text{ C1-IC\%} = r_p \text{ C2-IC\%} = [(3.20 - 3.00) * 0.04250 + 0.08600] * 100 = 9.45\%$$

Propane ISC

Table 16

Par Price ($/m^3)	r_p (%)
PP ≤ 88.10	10%
88.10 < PP ≤ 143.16	[(PP – 88.10) * 0.00202 + 0.10000] * 100
143.16 < PP ≤ 253.28	[(PP – 143.16) * 0.00111 + 0.21122] * 100
253.28 < PP	[(PP – 253.28) * 0.00059 + 0.33347] * 100
Maximum	36%

With a propane mix price of $78.96/m^3$, the first row in Table 16 for the price component would be used:

r_p C3-IC% = 10%

Butanes ISC

Table 17

Par Price ($/m³)	**r_p (%)**
PP ≤ 176.19	10%
176.19 < PP ≤ 286.31	[(PP – 176.19) * 0.00101 + 0.10000] * 100
286.31 < PP ≤ 506.55	[(PP – 286.31) * 0.00055 + 0.21122] * 100
506.55 < PP	[(PP – 506.55) * 0.00031 + 0.33235] * 100
Maximum	36%

With a butane mix price of $460.85/m^3$, the third row in Table 17 for the price component would be used:

r_p C4-IC% = [(460.85 – 286.31) * 0.00055 + 0.21122] * 100
= 30.7217%

Pentanes Plus ISC

Table 18

Par Price ($/m³)	**r_p (%)**
Price ≤ 251.70	10%
251.70 < Price ≤ 409.02	[(PP – 251.70) * 0.00071 + 0.10000] * 100
409.02 < Price ≤ 723.64	[(PP – 409.02) * 0.00039 + 0.21170] * 100
723.64 < Price	[(PP – 723.64) * 0.00020 + 0.33440] * 100
Maximum	40%

With a pentane plus spec price of $864.74/m^3$, the fourth row in Table 18 for the price component would be used:

r_p C5+-IC% = [(864.74 – 723.64) * 0.00020 + 0.33440] * 100
= 36.262%

Quantity Component

The quantity component is calculated using the total MRF eligible monthly production from all well events under a licence. Monthly production will be converted to GEV for the r_q formula for methane and ethane, and to OEV for the r_q formula for propane, butane and pentanes plus. For a licence that reports the following for a given month:

Raw gas production: 169.3 10^3m^3
Oil production: 64.2 m^3
Condensate production: 16.3 m^3
Total heat: 4,915.83 GJ

GEV = 169.3 + (64.2 * 1.7811) + (16.3 * 1.7811)
= 312.7 10^3m^3
OEV = (169.3 / 1.7811) + 64.2 + 16.3
= 175.6 m^3

The quantity component for each ISC is calculated using the following tables:

Methane and Ethane ISC

Table 19

GEV Quantity (10^3m^3)	r_q (%)
Q ≥ 345.5	0
Q < 345.5	[(Q – 345.5) * 0.0004937] * 100

Since Q is equal to 312.7 10^3m^3, the second row in Table 19 is used to calculate an r_q that applies to both C1-IC and C2-IC.

r_q = [(312.7 – 345.5) * 0.0004937] * 100
= -1.61934%

Propane, Butanes, and Pentanes Plus ISC

Table 20

OEV Quantity (m^3)	r_q (%)
Q ≥ 194.0	0
Q < 194.0	[(Q – 194.0) * 0.001350] * 100

Since Q is equal to 175.6 10^3m^3, the second row in Table 20 is used to calculate an r_q that applies to C3-IC, C4-IC and C5+-IC.

r_q = [(175.6 – 194.0) * 0.001350] * 100
= -2.484%

Calculation of Royalty Rate (R%)

Total royalty rate for methane:

R%C1-IC= r_p C1-IC% + r_q C1-IC%
= 9.45% + (-1.61934%)
= 7.83066%

Total royalty rate for ethane:

R%C2-IC = r_p C2-IC% + r_q C2-IC%
= 9.45% + (-1.61934%)
= 7.83066%

Total royalty rate for propane:

R%C3-IC = r_p C3-IC% + r_q C3-IC%
= 10% + (-2.484%)
= 7.516%

Total royalty rate for butane:

R%C4-IC = r_p C4-IC% + r_q C4-IC%
= 30.7217% + (-2.484%)
= 28.2377%

Total royalty rate for pentanes plus:

R%C5+-IC = r_p C5+-IC% + r_q C5+-IC%
= 36.262% + (-2.484%)
= 33.778%

If the heat content of methane, ethane, propane, butanes, and pentanes plus ISCs is known at the well event level, the WEARR of the well event could be determined. However, the energy content of the ISCs at the well event are not known or reported by the operator, therefore, the Facility Component Proportion (FCP) method is used to determine WEARR for a well event.

Facility Component Proportion (FCP) Method

The FCP method applies the gas composition of the facility to each well event which reports to this facility. The table below summarizes the facility to which the natural gas from the well event in this example flows to:

Reported Facility In-stream Components (ISCs)

Table 21

Product ISC (1)	Volume (10^3m^3) (2)	Heat (GJ) (3)	FCP (%) *= (3)/(sum of all ISCs)* (4)
C1-IC	2,382.7	88,161.652	81.5798% [A]
C2-IC	185.8	12,277.174	11.3606%
C3-IC	57.6	5,415.294	5.0110%
C4-IC	14.6	1,774.386	1.6419%
C5+-IC	2.9	439.494	0.4067%
Total	2,643.6	108,068.000	100%
*A. 81.5798% = 88,161.652 / 108,068.000 * 100*			

In Table 21 the last column (4) shows the FCP for this facility, which is calculated by dividing each ISC component of column (3) by the total ISCs of this column which is 108,068 GJ. The above FCP is applied to all well events which report to this facility. The total heat content of a well event can be obtained by applying the Stream Allocation Factor (SAF) and Owner Allocation Factor (OAF) to the total heat content of the facility, which is 108,068 GJ in this example.

Applying the above FCP percentages for each of the ISC to the total heat content for the well event in this example results in the ISC component of the well event as follows:

Well Event FCP Calculated ISCs

Table 22

Product (1)	Total Well Event Heat (2)	Calculated Facility FCP (%) *(column (4) Table 21)* (3)	Well Event (GJ) *= (2) * (3)* (4)
C1-IC	4,915.83	81.5798%	4,010.3243
C2-IC	4,915.83	11.3606%	558.4678
C3-IC	4,915.83	5.0110%	246.3322
C4-IC	4,915.83	1.6419%	80.7130
C5+-IC	4,915.83	0.4067%	19.9927
Total		100.00%	4,915.83

WEARR Calculation

Table 23

Product (1)	**Heat content (GJ)** *(Table 22 column (4))* **(2)**	**ISC Calculated Royalty Rate (%) (3)**	**Royalty Heat (GJ)** *= (2) * (3)* **(4)**
C1-IC	4,010.3243	7.83066%	314.0349
C2-IC	558.4678	7.83066%	43.7317
C3-IC	246.3322	7.516%	18.5143
C4-IC	80.7130	28.2377%	22.7915
C5+-IC	19.9927	33.778%	6.7531
Total	4,915.8300 GJ (6)		405.8255 (5)

WEARR = Royalty heat (GJ) for the well event / Total heat content (GJ) of the well

= (5) / (6)
= 405.8255 / 4,915.8300 * 100
= 8.2555%

The WEARR of 8.2555% is applied to the total Crown heat content of the well to determine the Crown royalty heat.

6.7.2 MWPE WEARR Example

The following is an example to illustrate the determination and calculation of royalty rates for a unit. In this example, there are five well events in a unit that deliver natural gas to Gas Plant (GP) 0001234. The GP reports the following in-stream components:

Table 24

Product (1)	**Volume (10^3m^3) (2)**	**Heat (GJ) (3)**	**FCP* (%)** *= (3)/(sum of all ISCs)* **(4)**
C1-IC	2,382.7	88,161.652	81.5798%
C2-IC	185.8	12,277.174	11.3606%
C3-IC	57.6	5,415.294	5.0110%
C4-IC	14.6	1,774.386	1.6419%
C5-IC	2.9	439.494	0.4067%
Total	2,643.6	108,068.000	100%

**FCP: Facility Component Proportion, obtained by dividing each component of column (3) by the total GP heat. For example, column (4): 81.5798% = 88,161.652 / 108,068.000 * 100, 11.3606% = 12,277.174 / 108,068.00 * 100, and so on.*

Of the five well events in this unit example, two are ARF (well events A and B) and three are MRF (well events C, D and E).

Table 25

	ARF Well Events		MRF Well Events		
Input for Unit	A	B	C	D	E
C1 Par Price	\$3.65	\$3.65	\$3.65	\$3.65	\$3.65
C2 Par Price	\$3.65	\$3.65	\$3.65	\$3.65	\$3.65
C3 Par Price (C3-MX price)			\$190.04	\$190.04	\$190.04
C4 Par Price (C4-MX price)			\$195.02	\$195.02	\$195.02
C5 Par Price (C5-SP price)			\$406.28	\$406.28	\$406.28
CO2 Content	1%	0%	-	-	-
H2S Content	0%	2.21%	-	-	-
AGF	1	1	-	-	-
Monthly Raw Gas Production (10^3m^3)	324.53	74.89	131.48	346.18	229.91
Monthly Raw Gas Heat Production (GJ) (Sum of all the wells heat is 43,771.90 GJs)	12,246.04	2,825.95	4,961.36	12,685.67	11,052.88
Total Monthly Production (Q in GEV)	-	-	131.48	346.18	229.91
Total Monthly Production (Q in OEV)	-	-	73.82	194.36	129.08
Maturity Eligible	-	-	Yes	No	Yes
Hours of Production	620	562	744	701	657
ADP (10^3m^3/day)	12.5625	3.1981	-	-	-
MD (m)	1,500	2,566	-	-	-
Depth Factor	1	1.6461	-	-	-

By adding the monthly raw gas heat production from Table 25, the total monthly reported stream heat for the unit is equal to 43,771.90 GJs. Multiplying this amount by the FCP, found in Table 24, for each product will give the stream heat by product:

Table 26

Product	FCP (%) (Table 24)	Stream Heat (GJ)
C1-IC	81.5798%	35,709.03
C2-IC	11.3606%	4,972.75
C3-IC	5.0110%	2,193.41
C4-IC	1.6419%	718.70
C5-IC	0.4067%	178.01
Total	100%	43,771.90

Using the above data and the appropriate royalty rate formulas from Sections 6.1 to 6.4, the royalty rate for each in-stream component at each well event may be determined (e.g. with a C3-MX par price of $190.04/m^3$, the C3-IC r_p formula is [(PP – 143.16) * 0.00111 + 0.21122] * 100, therefore r_p = 26.33% for MRF well events C, D and E):

Table 27

Product	Well Event				
C1-IC	A	B	C	D	E
(1) r_p	-3.83%	-3.83%	11.36%	11.36%	11.36%
(2) r_q	26.56%	-10.29%	-10.57%	0.00%	-5.71%
(3) = (1)+(2) R% = $r_p + r_q$	22.74%	5.00%	5.00%	11.36%	5.66%
C2-IC	A	B	C	D	E
(1) r_p	-3.83%	-3.83%	11.36%	11.36%	11.36%
(2) rq	26.56%	-10.29%	-10.57%	0.00%	-5.71%
(3) = (1)+(2) R% = $r_p + r_q$	23.14%	5.00%	5.00%	11.75%	5.66%
C3-IC	A	B	C	D	E
(1) r_p			26.33%	26.33%	26.33%
(2) r_q			-16.22%	0.00%	-8.76%
(3) = (1)+(2) R% = $r_p + r_q$	30.00%	30.00%	10.10%	26.33%	17.56%
C4-IC	A	B	C	D	E
(1) r_p			11.90%	11.90%	11.90%
(2) r_q			-16.22%	0.00%	-8.76%
(3) = (1)+(2) R% = $r_p + r_q$	30.00%	30.00%	5.00%	11.90%	5.00%
C5+-IC	A	B	C	D	E
(1) r_p			20.98%	20.98%	20.98%
(2) r_q			-16.22%	0.00%	-8.76%
(3) = (1)+(2) R% = $r_p + r_q$	40.00%	40.00%	5.00%	20.98%	12.21%

Once the royalty rates for the in-stream components have been calculated, the next step is to determine the base royalty heat by multiplying the royalty rates from Table 27 by the in-stream component stream heat from Table 26 (e.g. well event A C1-IC base royalty heat = 35,709.03 * 22.74%):

Table 28

Well Event	Product	Stream Heat (GJ)	RR (%)	Base Royalty Heat (GJ)
A	C1-IC	35,709.03	22.74%	8,119.340
	C2-IC	4,972.75	22.74%	1,130.679
	C3-IC	2,193.41	30%	658.024
	C4-IC	718.70	30%	215.609
	C5+-IC	178.01	40%	71.205
	Total	**43,771.90**		**10,194.857**
B	C1-IC	35,709.03	5.00%	1,785.451
	C2-IC	4,972.75	5.00%	248.638
	C3-IC	2,193.41	30%	658.024
	C4-IC	718.70	30%	215.609
	C5+-IC	178.01	40%	71.205
	Total	**43,771.90**		**2,978.927**
C	C1-IC	35,709.03	5.00%	1,785.451
	C2-IC	4,972.75	5.00%	248.638
	C3-IC	2,193.41	10.10%	221.564
	C4-IC	718.70	5.00%	35.935
	C5+-IC	178.01	5.00%	8.901
	Total	**43,771.90**		**2,300.488**
D	C1-IC	35,709.03	11.36%	4,057.438
	C2-IC	4,972.75	11.36%	565.029
	C3-IC	2,193.41	26.33%	577.431
	C4-IC	718.70	11.90%	85.538
	C5+-IC	178.01	20.98%	37.339
	Total	**43,771.90**		**5,322.774**
E	C1-IC	35,709.03	5.66%	2,019.639
	C2-IC	4,972.75	5.66%	281.250
	C3-IC	2,193.41	17.56%	385.205
	C4-IC	718.70	5.00%	35.935
	C5+-IC	178.01	12.21%	21.738
	Total	**43,771.90**		**2,743.767**

The average royalty rate is then found by dividing the product base royalty heat by the total stream heat at each well event and in-stream component (e.g. well event A C1-IC average royalty rate is 8,119.340/43,771.90 = 18.54921%):

Table 29

Well Event	Product	Stream Heat (GJ)	RR (%)	Base Royalty Heat (GJ)	Average RR (%)
A	C1-IC	35,709.03	22.74%	8,119.340	18.54921%
	C2-IC	4,972.75	22.74%	1,130.679	2.58312%
	C3-IC	2,193.41	30%	658.024	1.50330%
	C4-IC	718.70	30%	215.609	0.49257%
	C5+-IC	178.01	40%	71.205	0.16267%
	Total	**43,771.90**		**10,194.857**	**23.29087%**
B	C1-IC	35,709.03	5.00%	1,785.451	4.07899%
	C2-IC	4,972.75	5.00%	248.638	0.56803%
	C3-IC	2,193.41	30%	658.024	1.50330%
	C4-IC	718.70	30%	215.609	0.49257%
	C5+-IC	178.01	40%	71.205	0.16267%
	Total	**43,771.90**		**2,978.927**	**6.80557%**
C	C1-IC	35,709.03	5.00%	1,785.451	4.07899%
	C2-IC	4,972.75	5.00%	248.638	0.56803%
	C3-IC	2,193.41	10.10%	221.564	0.50618%
	C4-IC	718.70	5.00%	35.935	0.08210%
	C5+-IC	178.01	5.00%	8.901	0.02033%
	Total	**43,771.90**		**2,300.488**	**5.25563%**
D	C1-IC	35,709.03	11.36%	4,057.438	9.26950%
	C2-IC	4,972.75	11.36%	565.029	1.29085%
	C3-IC	2,193.41	26.33%	577.431	1.31918%
	C4-IC	718.70	11.90%	85.538	0.19542%
	C5+-IC	178.01	20.98%	37.339	0.08530%
	Total	**43,771.90**		**5,322.774**	**12.16025%**
E	C1-IC	35,709.03	5.66%	2,019.639	4.61401%
	C2-IC	4,972.75	5.66%	281.250	0.64254%
	C3-IC	2,193.41	17.56%	385.205	0.88003%
	C4-IC	718.70	5.00%	35.935	0.08210%
	C5+-IC	178.01	12.21%	21.738	0.04966%
	Total	**43,771.90**		**2,743.767**	**6.26833%**

The contribution percentage, as determined by the proportion of the unit’s total production that each well event provides, is calculated next:

Table 30

	Unit Well Events				
	A	B	C	D	E
Well Event Production (10^3m^3) (Table 25)	324.53	74.89	131.48	346.18	229.91
Unit Production (10^3m^3)	1106.99	1106.99	1106.99	1106.99	1106.99
Contribution	29.31643%	6.76519%	11.87725%	31.27219%	20.76893%

The contribution percentage is applied to each well event's average royalty rate to determine the weighted royalty rate contribution of each well event to the unit WEARR, as shown in Table 31 (e.g. well event A weighted royalty rate is 23.29087% * 29.31643% = 6.82805%):

Table 31

Well Event	Product	Stream Heat (GJ)	RR (%)	Base Royalty Heat (GJ)	Average RR (%)	Contribution (%)	Weighted RR(%)
A	C1-IC	35,709.03	22.74%	8,119.340	18.54921%		
	C2-IC	4,972.75	22.74%	1,130.679	2.58312%		
	C3-IC	2,193.41	30%	658.024	1.50330%		
	C4-IC	718.70	30%	215.609	0.49257%		
	C5+-IC	178.01	40%	71.205	0.16267%		
	Total	**43,771.90**		**10,194.857**	**23.29087%**	**29.31643%**	**6.82805%**
B	C1-IC	35,709.03	5.00%	1,785.451	4.07899%		
	C2-IC	4,972.75	5.00%	248.638	0.56803%		
	C3-IC	2,193.41	30%	658.024	1.50330%		
	C4-IC	718.70	30%	215.609	0.49257%		
	C5+-IC	178.01	40%	71.205	0.16267%		
	Total	**43,771.90**		**2,978.927**	**6.80557%**	**6.76519%**	**0.46041%**
C	C1-IC	35,709.03	5.00%	1,785.451	4.07899%		
	C2-IC	4,972.75	5.00%	248.638	0.56803%		
	C3-IC	2,193.41	10.10%	221.564	0.50618%		
	C4-IC	718.70	5.00%	35.935	0.08210%		
	C5+-IC	178.01	5.00%	8.901	0.02033%		
	Total	**43,771.90**		**2,300.488**	**5.25563%**	**11.87725%**	**0.62422%**
D	C1-IC	35,709.03	11.36%	4,057.438	9.26950%		
	C2-IC	4,972.75	11.36%	565.029	1.29085%		
	C3-IC	2,193.41	26.33%	577.431	1.31918%		
	C4-IC	718.70	11.90%	85.538	0.19542%		
	C5+-IC	178.01	20.98%	37.339	0.08530%		
	Total	**43,771.90**		**5,322.774**	**12.16025%**	**31.27219%**	**3.80278%**
E	C1-IC	35,709.03	5.66%	2,019.639	4.61401%		
	C2-IC	4,972.75	5.66%	281.250	0.64254%		
	C3-IC	2,193.41	17.56%	385.205	0.88003%		
	C4-IC	718.70	5.00%	35.935	0.08210%		
	C5+-IC	178.01	12.21%	21.738	0.04966%		
	Total	**43,771.90**		**2,743.767**	**6.26833%**	**20.76893%**	**1.30186%**

The sum of the weighted royalty rates results in the WEARR of the unit.

Table 32

Well Event	**Weighted Royalty Rate (%)**
A	6.82805%
B	0.46041%
C	0.62422%
D	3.80278%
E	1.30186%
Total	**13.01733%**

The WEARR of 13.01733% is applied to the total Crown heat content of the unit to determine the Crown royalty heat.

6.8 Raw Gas Allocation Well Event Average Royalty Rate (RGAWEARR)

The Alberta Natural Gas Royalty Guidelines, 2009 continue to apply for all other matters referring to RGA except for the MRF royalty calculation (See Chapter IV, Sections 1.7 and 1.8, Chapter VII, Section 1.5.5, and Appendix I, Section 4).

The royalty rate used for the assessment of MRF eligible gas quantities will continue to be based on the ISC breakdown of that gas as reported on the Raw Gas Allocation (RGA) submission, but will be using the royalty rate calculated under the MRF regime.

For MWPE, the royalty rate of each stream as calculated under the appropriate regime will be weighted to reflect that stream's contribution to the total production of the MWPE.

RGAWEARR Example:

ISC factors on the RGA submission in Petrinex by a raw gas seller are as follows:

Table 33

ISC Product	**Volume (10^3m^3)**	**Heat Content (GJ)**
C1-IC	67.6	2,550
C2-IC	2.7	177
C3-IC	1.1	104
C4-IC	0.4	49
C5+-IC	0.3	53
C02-IC	0.1	0
N2-IC	1.0	0
Total	73.2	2,933

The calculated post C* royalty rates are:

C1-IC
  r_p = 5.36000%, r_q = -0.27154%,
  R% = 5.08846%
C2-IC
  r_p = 5.36000%, r_q = -0.27154%,
  R% = 5.08846%

C3-IC
  r_p = 11.99778, r_q = -0.41850%,
  R% = 11.57928%

C4-IC
  r_p = 11.61095, r_q = -0.41850%,
  R% = 11.19245%

C5+-IC
  r_p = 20.08129, r_q = -0.41850%,
  R% = 19.66279%

Table 34

ISC Product	**Heat Content (GJ) (1)**	**ISC Component Factor** *= 1/6* **(2)**	**Royalty Rate (%) (3)**	**Base Royalty Heat (GJ)** *= 1*3* **(4)**	**Average Royalty Rate (%)** *= 3*2* **(5)**
C1-IC	2,550	0.869416979	5.08846%	129.756	4.42399%
C2-IC	177	0.060347767	5.08846%	9.007	0.30708%
C3-IC	104	0.035458575	11.57928%	12.042	0.41058%
C4-IC	49	0.016706444	11.19245%	5.484	0.18699%
C5+-IC	53	0.018070235	19.66279%	10.421	0.35531%
Totals	2,933(6)			166.710 (7)	5.68395% (8)

RGAWEARR = total base royalty heat (GJ) for the well event /total heat content (GJ) of the well event

  = (7) / (6) = 166.710/2,933
  = 5.68395% (8)

The RGAWEARR of 5.68395% is applied to the total Crown heat of the well to determine the Crown royalty heat.

6.9 Default Royalty Rates / Royalty Calculation Defaults

The Alberta Natural Gas Royalty Guidelines, 2009 continue to apply to both ARF and MRF wells for default situations, as limited by the timelines included therein (See Chapter II, Sections 1.8, Chapter VII, Section 1.6.15, and Appendix O) and the following changes.

6.9.1 Missing Production

In a default situation due to missing production information under MRF, the default WEARR or RGAWEARR used for the assessment of Crown royalty will no longer be calculated by using the maximum allowable value of the quantity component of the royalty rate. Instead the maximum R% of 36% will be used. For gas products, the corresponding maximum R% will also be used. If the stream is a MWPE, and production does not exist for any participating wells, then the default ARF well event royalty rates will continue to be used.

6.9.2 Production Allocation Discrepancies (PAD)

In a default situation due to PAD under MRF, the default WEARR or RGAWEARR used for the assessment of Crown royalty will no longer be calculated by using the maximum allowable value of the quantity component of the royalty rate. Instead the maximum R% of 36% will be used. For gas products, the corresponding maximum R% will also be used. If the stream is a MWPE comprised of ARF and MRF wells, the default royalty rates for the stream will be calculated using a weighting of the individual producing well event's default royalty rate.

6.9.3 Injection Credits

In a default situation that occurs in the case of an Injection Credit under MRF, the default R% is 0%.

6.9.4 Unable to Calculate C*

When C* cannot be calculated for an MRF well, default Post C* royalty rates are applied. When C* cannot be calculated for an ARF well that temporarily becomes part of the MRF regime due to new drilling activity, ARF values for royalty rates are applied.

6.9.5 Summary of MRF Default Situations

Table 35

Form	Default Item	Default Situation	Default
Allocation	WEARR Royalty Rates of Products	Allocation > Production.	R% = max for Crown Royalty
Volumetric	WEARR/ RGAWEARR Royalty Rates of Products	If the well production is not filed	R% = max for Crown Royalty
Volumetric	WEARR/ RGAWEARR Royalty Rates of Products	Any default situation for Injection Credit	R% = 0%
Well Data	WEARR/ RGAWEARR Royalty Rates of Products	C* is 0 for a C* well	R% = the post C* calculated royalty rates for gas and gas products
Well Data	WEARR/ RGAWEARR Royalty Rates of Products	C* is 0 for an ARF well with new re-entry activity after January 1, 2017	R% = the royalty rate under the ARF regime (WEARR calculation for gas, and prescribed rates for gas products)

7. WELL COST SUBMISSIONS

In order for Alberta Energy to determine the Alberta Capital Cost Index (ACCI) it is required that industry submit drilling and completion costs for all active Crown wells.

- Active Well, for the purpose of well cost submissions, is any well that has a well event with a producing status or a status of "drain".

The submission of costs is done in Petrinex in the Drilling and Completion Costs menu and are made at a well event level. Costs need to be submitted by using the Unique Well Identifier (UWI) of a drilled well event. If a well event has been created due to a completion of a new zone on a previously drilled well event, the costs will be submitted using the UWI of the drilled well event in which the new zone was completed on. All activities performed on or after January 1, 2017 must have their costs submitted regardless of whether the well is qualified under MRF or ARF as they are used in the calibration of the ACCI for that year. Wells that are 100% freehold do not require costs to be submitted.

Well events that were assigned an active status during the period of January 1, 2017 to December 31, 2018 are required to have two cost submission types, estimates and actuals. Well events that are assigned an active status as of January 1, 2019 and on will only be required to submit actual costs. Submissions are based on a specific well event's activities of drilling, completion, re-completion and re-entry. The cost submissions require the selection of the specific activity type and the entry of an activity date, total estimated costs, total actual costs and attachments detailing the costs. The activity date for each activity is as follows:

- Drilling – spud date
- Completion – final treatment date of the completion
- Re-completion – first fracture treatment date
- Re-entry – date the re-entry of the well commences

The activity date must be unique with each activity submission as it is used to differentiate between multiple re-entry or re-completion cost rows. The activity types and costs are explained in greater detail in the subsequent sections.

The Drilling and Completion Costs (DCC) menu in Petrinex is a newly added user role that must be assigned by the Petrinex Business Associates User Security Administrator in order for a user to view and access the Drilling and Completion Cost menu. For more information regarding the addition of this user role please visit the Petrinex Initiatives page (http://www.petrinex.ca/33.asp).

Figure 1 and 2 below are Petrinex images which show the Query Drilling and Completion Cost screen for reference. For further details on steps to submit costs in Petrinex please visit the Petrinex Initiative Page, MRF Functions (http://www.petrinex.ca/207.asp). MRF learning modules are also available in the Petrinex Learning Centre (http://www.petrinex.ca/17.asp).

Figure 1

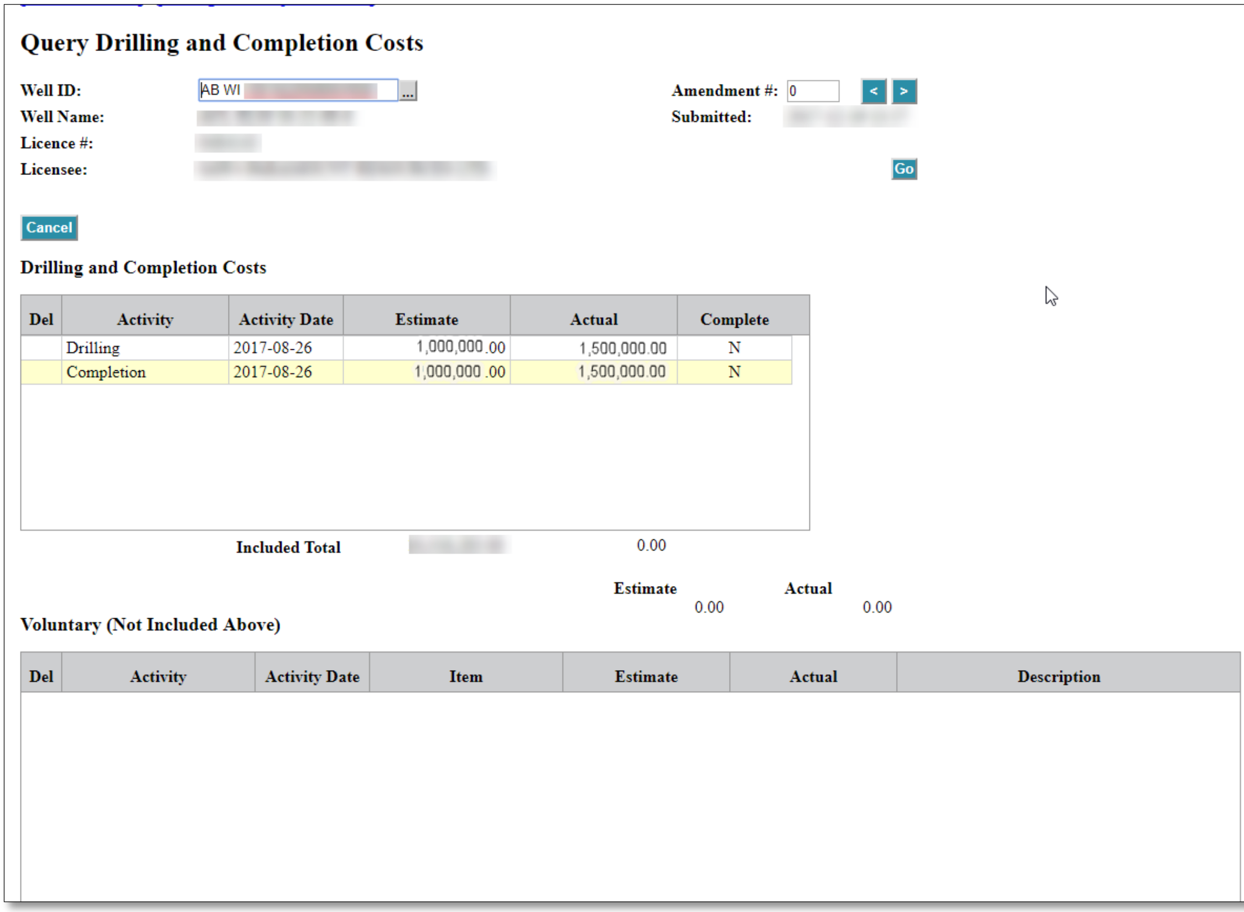
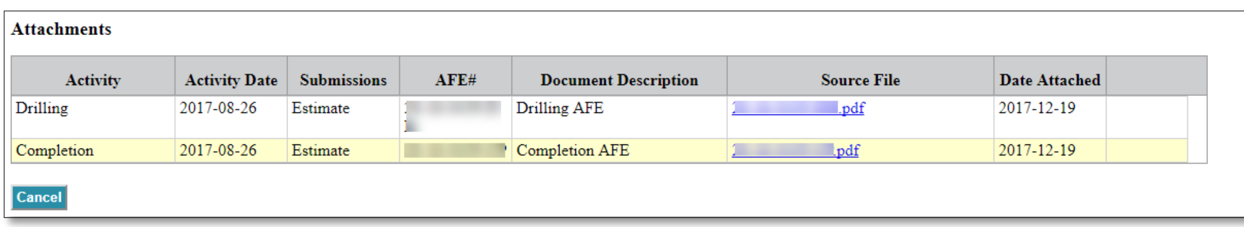


Figure 2



Cost attachments are only accepted in the following formats:

- Estimates can be submitted in PDF, DOC, DOCX, XLS, or XLSX
- Actuals can be submitted in XLS, XLSX, or CSV

7.1 Cost Types

In order to ensure accuracy of the ACCI, Alberta Energy requires costs to be submitted for all drilling, completion, re-entry, and re-completion activities performed on a well from January 1, 2017 onward. Estimates are the first costs to be submitted, as these are generally known before the activities are performed and are only required on wells that have an active status date between January 1, 2017 and December 31, 2018. Actual costs filings will follow with a more detailed transaction listing. The gross costs for a well event are to be submitted with all included and excluded costs; there is no need to separate the different costs prior to submission. Please see the Information Letter 2017-09 which outlines included and excluded costs (http://inform.energy.gov.ab.ca/Documents/Published/IL-2017-09.pdf). There are no formal templates for submitting estimate or actual attachments and most company formats are acceptable.

7.1.1 Estimated Costs

Estimated Costs are only required for well events that have an active status date between January 1, 2017 and December 31, 2018. Any well events with an active status date of January 1, 2019 going forward no longer require estimate submissions. Estimates are to be submitted in Petrinex by the end of the last business day of the second month from the well event's active status date or first treatment date. For example, a well event given an active status of gas flowing for June 6, 2018 must submit cost estimates by end of day August 31, 2018. Similarly, a well event that was re-completed with fracture treatment dates starting July 7, 2018 will need to submit re-completion estimates by the end of September 30, 2018. Please be aware that the three month deadline from the status date or treatment dates is to account for the fact that these activities are often set in the month after the activity has occurred. Therefore, if statuses or treatment dates are set retroactively more than two months behind, the well event will automatically be in error by the end of the month. In this case the well cost reporter must be ready to submit the costs in the same month the status or treatment information is received. Estimates are entered in the estimates field based on the activity type and activity date, as seen in Figure 1. The supporting attachments as seen in Figure 2 are submitted in the form of an Authorization for Expenditure (AFE) and must share the same activity date as the associated activity cost field otherwise warnings may continue to show on the non-compliance report.

7.1.2 Actual Costs

Actual costs are required to be submitted in Petrinex by the last business day in April the year following the calendar year the well event was given an active status date or re-completion treatment dates. For example, a well event given an active status of crude oil flowing for February 18, 2018 must submit actual costs by April 30, 2019. Similarly, a well that was re-completed with the first fracture treatment date of November 12, 2018 will need to submit actuals by the end of April 2019. Actual costs are entered on the same row as the previously submitted estimates field and corresponding activity and activity date. The supporting attachment is recommended to be an electronic transaction listing (e.g. CSV) that should include, but is not limited to: the vendor name, invoice number, invoice date, transactions description, AFE number, account number, account description, cheque number, payment date and any other information necessary to identify the nature and purpose of the transaction. All costs for a well event are to be submitted regardless of the year they were incurred (e.g. well event A is given an active status in 2017 and its actual costs are finalized in March 2018, all costs from 2017 and 2018 should be accounted for in the submission).

Amendments can be made in Petrinex at any time before or after a well events submission deadline. Amendments made after the well event's actual cost deadline will NOT be used in the calculation of the ACCI, but will be accepted for further use in recalibrations of drilling and completion costs and future year cost comparisons. Please be aware that all cost submissions are subject to audit and Alberta Energy will contact the company on record for more information if submitted costs are not sufficient.

7.2 Activity Types

In order to appropriately collect costs based on well activities, four different activity types will require estimate and actual cost submissions.

7.2.1 Drilling Activity

Drilling is an activity type code used for collecting costs associated with the initial drilling of a new well where no previous drilling has been completed and the rig release date is the same as the first event sequence.

7.2.2 Completion Activity

Completion is an activity type code used for collecting costs associated with the initial completion of a new well, which include fracturing, where no previous completion activities have been done and the rig release date is the same as the first event sequence.

7.2.3 Re-entry Activity

Re-entry is an activity type code used for collecting costs associated with deepening or lengthening an existing well or drilling new well events, where the rig release date of the new well event is different from previously drilled well events under the same licence.

7.2.4 Re-completion Activity

Re-completion is an activity type code used for collecting costs associated with fracturing an existing well by adding proppant more than 45 days from the fractured well event's active status date or from another set of previous fracture activity treatment dates. Fracture data is received through the AER's DDS.

7.3 Drilling and Completion Cost Non-Compliance Report

Industry will be notified on the Petrinex MRF Drilling and Completion Cost Non-Compliance Report when costs are to be submitted for the specific well event's activity. This report shows warnings and errors associated with cost estimates and actuals.

- Warnings are created when an activity of drilling, completion, re-completion or re-entry has been reported by the licensee or operator and the well event has an active status.

- Errors are triggered when a submission of costs has not been made by the warning-based deadline.

This report can be run manually at any point in a month and otherwise will be automatically sent to DCC User's Petrinex inbox at the end of each month. There are two DCC non-compliance report types that a Petrinex user can request, a monthly or an annual. The monthly report will show all warnings and errors for estimate and actual costs as of the date it is requested. The annual report will show only warnings for well events with an upcoming actual cost submission deadline, as well as errors for well events that have past their actual cost submission deadline. The Petrinex warning and error codes are divided into monthly and annual based on the prefixes of DCCM for monthly and DCCA for annual. The table below, Table 36, outlines the rules that will trigger warnings and errors to appear on the Petrinex MRF DCC non-compliance report for both estimate and actual cost submissions, as well as the associated Petrinex codes.

Please be aware that any errors received are subject to penalties, as per Section 7.5.

Table 36

Activity Type	**Warning**	**Petrinex Code (Warning)**	**Error**	**Petrinex Code (Error)**
Drilling (Estimate)	Well event has an active status and no drilling estimates have been entered.	DCCA001, DCCM001,	Well event drilling cost estimates were not submitted by the estimate deadline (See 7.1.1).	DCCA002, DCCM002
Completion (Estimate)	Well event has an active status and no completion estimates have been entered.	DCCA001, DCCM001,	Well event completion cost estimates were not submitted by the estimate deadline (See 7.1.1).	DCCA002, DCCM002
Re-entry (Estimate)	Well event has an active status and no re-entry estimates have been entered.	DCCA001, DCCM001,	Well event re-entry cost estimates were not submitted by the estimate deadline (See 7.1.1).	DCCA002, DCCM002
Re-completion (Estimate)	Fracture treatment dates are more than 45 days from the well event's active status date or previous fracture treatment dates and no re-completion estimates have been entered.	DCCA001, DCCM001,	Re-completion cost estimates were not submitted by the end of the estimate deadline (See 7.1.1).	DCCA002, DCCM002

Attachment (Estimates)	Well event has an estimate submission without a supporting attachment.	DCCM003, DCCA003	Well event has an estimate submission but has not submitted a supporting attachment by the estimate deadline (See 7.1.1).	DCCM004, DCCA004
Drilling (Actuals)	Well event has an active status but no drilling actual costs have been entered.	DCCM005	Drilling cost actuals were not submitted by April 30th of the year following the active status date.	DCCA005
Completion (Actuals)	Well event has an active status and no completion actual costs have been entered.	DCCM005	Completion cost actuals were not submitted by April 30th of the year following the active status date.	DCCA005
Re-entry (Actuals)	Well event has an active status and no re-entry actual costs have been entered.	DCCM005	Re-entry cost actuals were not submitted by April 30th of the year following the active status date.	DCCA005
Re-completion (Actuals)	Fracture treatment dates are more than 45 days from the well events active status date or previous fracture treatment dates and no re-completion actuals have been entered.	DCCM005	Re-completion cost actuals were not submitted by April 30th of the year following the active status date or the last treatment date.	DCCA005
Attachment (Actuals)	Well event has an actual submission without a spreadsheet attachment.	DCCM006	Well event has an actual cost submission but a spreadsheet was not submitted by April 30th of the year following the active status or last treatment date.	DCCA006

7.4 Voluntary Costs

Costs related to drilling and completion activities that are not specifically included in the required costs are categorized as voluntary costs. These costs are to be entered in the voluntary cost field in Petrinex and will be reviewed by Alberta Energy to determine if they should be part of the required costs. The licensee must provide a detailed description of the nature of the costs and how they are applicable to the drilling and completion of a well

7.5 Penalties

Penalties will be charged to the licensee at the licence level and are based on well event errors received on the Petrinex MRF DCC Non-Compliance Report (please refer to Table 36 for error codes and descriptions). Penalties will only be applied to actual cost submissions and are effective for the April 2019 deadline. The first time an error for a well event triggers a penalty, the penalty is $1,000. Consequently, if the same error remains for the well event, a monthly re-occurring penalty charge of $5,000.00 will be issued until a cost submission has been made that removes the error. Penalties are well event, error code and time specific, therefore if subsequently a different error is made, or the error is in regards to a different well event, or if it is made at a later date, the penalty charge will start again at $1,000 and progress to $5,000 in the following months if not fixed. As only one penalty can be applied to a licence per month, if there is more than one error occurring in a month, only the highest penalty will be charged (ex. well event A is in error for the first time and well event B has a re-occurring error, the licence will receive a $5000 penalty charge for the re-occurring error).

8. REPORTS

8.1 C* Drawdown Report

Revenue drawdown details will be outlined on the report allowing the licensee to manage their C* balance. Previous and total revenue values will be provided every month. The report will only show the current production period revenue details unless there has been a prior production period amendment, in which case those details will be provided. If a licence does not produce in a month the licence will not show on that production month's report. Once the C* is fully drawn down the licence will no longer show on the report. A sample report can be found in Appendix A.

8.2 C* Calculation Report

The C* calculation report shows all of the factors used in the Drilling and Completion Cost Allowance formula for each individual licence. This report only presents calculations that happened in the month the report was generated, therefore it will only show a licence's new C* calculation or a licence's recalculated C*. The legend is used to identify what changes occurred that caused the recalculation. If no new C* is calculated or no changes have occurred to recalculate the C*, the licence will not appear on the report. A sample report can be found in Appendix B.

APPENDIX

Appendix A

RAMMRF0005
Confidential

Alberta Energy - Royalty Operations
C* Draw Down Details

Issue Date: 2017/11/23
Business Period: 2017/11

Licence: XXXXXX
Licensee Id: XXX
Licensee Name: COMPANY

Effective Date	Total C* ($)	Previous Revenue Taken ($)	Total Oil Revenue Taken ($)	Total Condensate Revenue Taken ($)	Total Gas & Gas Products Revenue Taken ($)	Total Revenue Taken ($)	C* Remaining ($)
2017/08/01	541,216.70	104,161.15	130,365.15	0.00	29,741.57	160,106.72	381,109.98
		Total		0.00			

Well Event Id	Production Period	Product	Price	Volumes	Unit of Measure	Revenue($)
	2017/10	OIL	333.76	87.500000000	m^3	29,204.00
	Sub-Total					**29,204.00**
	2017/09	C2-MX	1.20	19.585405773	GJ	23.50
		C3-MX	164.85	21.699999953	m^3	3,577.24
		C4-MX	180.92	60.400000000	m^3	10,927.57
		C5-MX	354.88	15.299999995	m^3	5,429.66
		GAS	1.20	5,652.999942902	GJ	6,783.60
		OIL	316.59	214.000000000	m^3	67,750.26
	Sub-Total					**94,491.83**
Well Event Total						**123,695.83**

Appendix B

Government

FDN000067
Confidential

Alberta Energy - Royalty Operations
C* Report

Issue Date: 2018-02-21 10:18 PM

Licensee BAID: XXXX
Licensee Legal Name: COMPANY LTD.

Licence Number	C* Eff. Date	Total C*	Total C* ERP	Adjustments	Formula Type	Reason	TVD	TLL	Y Factor	TLLi	TPPe	TVDa	TVDp
XXXXXXX	2017/08/01	$7,429,347.00	$0.00	$7,429,347.00	CSTARSL		701.00	7,610.00	0.93	0.00	2,945.00	701.00	701.00

Well ID	Spud Date	Finish Drilling Date	Rig Release Date	Total Depth	Well TVD	Kick Off Point	Measured Depth	Well TLLi	Well TPPe
000000000000W500	2017/08/14	2017/08/28	2017/08/30	8,096.00	701.00	0.00	8,096.00	0.00	2,945.00

Licence Number	C* Eff. Date	Total C*	Total C* ERP	Adjustments	Formula Type	Reason	TVD	TLL	Y Factor	TLLi	TPPe	TVDa	TVDp
XXXXXXX	2017/10/01	$21,761,420.00	$0.00	$21,761,420.00	CSTARSL		4,724.00	1,486.00	1.00	0.00	2,412.50	4,724.00	4,724.00

Well ID	Spud Date	Finish Drilling Date	Rig Release Date	Total Depth	Well TVD	Kick Off Point	Measured Depth	Well TLLi	Well TPPe
000000000000W500	2017/10/16	2017/10/29	2017/10/31	6,210.00	4,724.00	0.00	6,210.00	0.00	2,412.50

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Legend:

Reason:

DDDC - Directional Drilling Depth Changed, EEA - Opt-In Approved, EER - Opt-In Rejected, FDDC - Finish Drilling Date Changed, LA - Licence Abandoned, LC - Licence Cancelled, LOA - Licence Override Approved, LOD - Approved Licence Override Deleted, NL - New Licence
NW - New Well, PA - Proppant Added, PC - Proppant Changed, PD - Proppant Deleted, PDO - First Producing Occurrence, PECRIC - PE CR Interest Change To Non-Zero, RRDC - Rig Release Date Changed, SDC - Spud Date Changed, SREE - System Revoked Opt In
TDC - Total Depth Changed, TVDC - True Vertical Depth Changed, WD - Well Deleted, WEAIC - Well Event EUB Active Indicator Change to Y, WESD - Well Event Status Deleted, WESI - Well Event Status Inserted, WESU - Well Event Status Updated
ERPA - Well event(s) tied to ERP project, ERPD - Well event(s) deleted from ERP project, EHRPA - well event(s) tied to EHRP project, EHRPD - Well event(s) deleted from EHRP project, FVPPDC - First Volumetric Production Period Date Change, FVPPDD - First Volumetric Production Period Date Deleted

Formula Type:

CSTARLEN - C* formula for Lengthening, CSTARML – C* formula for Multi-leg well, CSTARREFRAC - C* formula for re-fracturing, CSTARSL - C* formula for Single leg

Other:

TVD - True Vertical Depth, TVDa - Average True Vertical Depth, TVDp - Average True Vertical Depth for Re-fracturing, TLL - Total Lateral Length, TLLi - Total Lateral Length Incremental, TPPe - Total Proppant Placed Equivalent