Alberta Department Energy

Information on the New Royalty Framework

For the October 30/31, 2008 Training Sessions

Gas Royalty Calculation Unit
10/17/2008

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DISCLAIMER

THIS DOCUMENT IS FOR INFORMATIONAL PURPOSES ONLY, PENDING APPROVAL OF THE NATURAL GAS ROYALTY REGULATIONS 2009 AND THE NATURAL GAS DEEP DRILLING REGULATIONS. CONTENTS OF THIS DOCUMENT MAY EVOLVE WITH THE LEGISLATIVE PROCESS.

SECTION 1 - SUMMARY

The New Royalty Framework (NRF) for Natural Gas will be implemented for the January 2009 production period which is invoiced in the March 2009 calendar month.

A new royalty formula will be used to calculate royalty rates for methane and ethane. This new royalty formula consists of the sum of a price component and a quantity component. The new royalty rates will range from 5% to 50%. Propane and butanes, will have fixed royalty rates of 30%, whereas pentanes plus will have a fixed royalty rate of 40%. The sulphur royalty rate remains unchanged at 16.66667%.

The Natural Gas Deep Drilling Program will also commence starting January 2009 production month, as a royalty adjustment for natural gas wells with production at true vertical depths greater than 2,500 metres. The benefit for this program will be based on the measured depth of the deepest producing interval. Incremental benefits will be available for exploratory wells, over development wells.

Under the New Royalty Framework, the department will implement changes to the monthly and annual allowable cost processes. The Unit Operating Cost Rate will no longer be used to determine operating cost deductions, in its place actual operating costs will be deducted for owners. The Corporate Effective Royalty Rate will be replaced with a Facility Effective Royalty Rate, which will be used to determine the monthly and annual Crown share of allowable costs, including capital, operating and custom processing cost allowances. The Facility Effective Royalty Rate will be applied to each client at each facility.

SECTION 2 - NEW ROYALTY FRAMEWORK FORMULA

2.1 Overview

The New Royalty Formula for Natural Gas will be implemented for the January 2009 production period, March 2009 calendar month. A new royalty formula will be used to calculate royalty rates. Vintage (old and new gas) will be eliminated.

Methane, Ethane and Extracted Ethane

A new royalty rate formula for methane ISC, ethane ISC and extracted ethane will be used to calculate their respective royalty rates. This new royalty formula consists of the following: a price component (r_p), a quantity component (r_q), and their total royalty rate (R%) which is the sum of the price and quantity components, as shown below:

R% = Price Component ($r_{p\%}$) + Quantity Component ($r_{q\%}$)

R% has a minimum of 5% and a maximum of 50%.

Propane, Butanes, and Pentanes Plus

Whether extracted at a gas plant or left in the gas stream (as an ISC), propane, butanes and pentanes plus royalty rates are fixed rates, as follows:

Propane:	30%.
Butanes:	30%.
Pentanes Plus:	40%.

Sulphur

The sulphur royalty rate remains unchanged at 16.66667%.

2.2 Royalty Formula: Methane ISC, Ethane ISC and Extracted Ethane

The determination of the royalty rate for methane ISC, ethane ISC and extracted ethane is based on the sum of the price and quantity components. Determination and calculation of each of these components are presented in this section.

2.2.1 Price Component (r_p):

The price component of the new royalty formula royalty rate is determined by the monthly methane or ethane par price as per the following table:

Table 2.2.1.1 - Price Component (r_p)

Price ($/GJ)	r_p
PP ≤ 7.00	(PP – 4.50) * 0.0450
7.00 < PP ≤ 11.00	(PP – 7.00) * 0.0300 + 0.1125$^{(A)}$
PP > 11.00	(PP – 11.00) * 0.0100 + 0.2325$^{(B)}$
Maximum	30%
Minimum	Can be negative (-20.25% if PP=0)

Note:

A. Where 0.1125 = (PP – 4.50) * 0.0450 at its maximum value of PP = 7.00

⇨ (7.00 - 4.50) * 0.0450 = 2.50 * 0.0450 = 0.1125

B. Where 0.2325 = (PP – 7.00) * 0.0300+ 0.1125 at its maximum value of PP = 11.00

⇨ (11.00 – 7.00) * 0.0300 + 0.1125 = 4.00 * 0.0300 + 0.1125 = 0.2325

Where PP = Par Price:
The par price is a provincial weighted price determined by the department and published in its Information Letter for each production month. Determination of the par price has not changed under the NRF.

The following are examples to illustrate the calculation of the price component rate (r_p%): ***(Note: Throughout this document there are a number of examples which may include rounding of calculation in order to simplify presentation of the material.)***

Example 1:
If the PP, as determined and published by the department, for methane is $6.60/GJ, then r_p is calculated as follows:

Since the PP of $6.60/GJ is less than $7.00/GJ, r_p is calculated using the equation in the first row of Table 2.2.1.1, as follows:

$$\begin{aligned} r_p &= (PP - 4.50) * 0.0450 \\ &= (6.60 - 4.50) * 0.0450 \\ &= (2.10) * 0.0450 \\ &= 0.0945 \end{aligned}$$

The price component rate for methane for this production month is 9.45%.

Example 2:
If the PP, as determined and published by the department, for ethane is $4.00/GJ, then r_p is calculated as follows:

Since the PP of $4.00/GJ is less than $7.00/GJ, r_p is calculated using the equation in the first row of Table 2.2.1.1, as follows:

$$\begin{aligned} r_p &= (PP - 4.50) * 0.0450 \\ &= (4.00 - 4.50) * 0.0450 \\ &= (-0.50) * 0.0450 \\ &= -0.0225 \end{aligned}$$

The price component rate for ethane for this production month is -2.25%, this negative rate is acceptable as the price component can be negative.

Example 3:
If the PP, as determined and published by the department, for methane is \$8.50/GJ, then r_p is calculated as follows:

Since the PP of \$8.50/GJ is less than \$11.00/GJ and greater than \$7.00, r_p is calculated using the equation in the second row of Table 2.2.1.1, as follows:

$$\begin{aligned} r_p &= (PP - 7.00) * 0.0300 + 0.1125 \\ &= (8.50 - 7.00) * 0.0300 + 0.1125 \\ &= 1.50 * 0.0300 + 0.1125 \\ &= 0.045 + 0.1125 \\ &= 0.1575 \end{aligned}$$

The price component rate for methane for this production month is 15.75%.

Example 4:
If the PP, as determined and published by the department, for ethane is \$18.25/GJ, then r_p is calculated as follows:

Since the PP of \$18.25/GJ is greater than \$11.00, r_p is calculated using the equation in the third row of Table 2.2.1.1, as follows:

$$\begin{aligned} r_p &= (PP - 11.00) * 0.0100 + 0.2325 \\ &= (18.25 - 11.00) * 0.0100 + 0.2325 \\ &= 7.25 * 0.0100 + 0.2325 \\ &= 0.0725 + 0.2325 \\ &= 0.3050 \end{aligned}$$

The price component rate for ethane for this production month is capped at 30%.

2.2.2 Quantity Component (r_q):

The quantity component of the new royalty formula royalty rate is based on the average daily production (ADP) of the well event. The quantity component is adjusted for either the depth of the well event and/or the acid gas content of the well event.

Determination of the quantity component is based upon the following table:

Table 2.2.2.1 Quantity Component (r_q)

Quantity ($10^3m^3/d$)	r_q
ADP≤ (6 * DF)	[ADP – (4 * DF)] * (0.0500/DF)
(6 * DF) < ADP ≤ (11* DF)	[ADP – (6 * DF)] * (0.0300/DF) + 0.1000
ADP > (11* DF)	[ADP – (11 * DF)] * (0.0100/DF) + 0.2500
Maximum	30%
Minimum	Can be negative

Where the parameters identified in the table above are defined in the following sections.

2.2.2.1 ADP = Average Daily Production

Under the current royalty regime the ADP is used to determine the low productivity well allowance; this will be discontinued effective the January 2009 production period.

Under the NRF there is no low productivity well allowance. As can be seen from Table 2.2.2.1 the ADP of the well event determines which of the three equations to use in order to calculate the quantity component royalty rate (r_q).

The ADP for a well event is the total raw gas production in thousand cubic metres (10^3m^3) for the month divided by the total hours of production in that month multiplied by 24. The ADP formula is as follows:

$$\mathbf{ADP} = \frac{\textbf{total raw gas production}}{\textbf{total hours of production}} \times \mathbf{24}$$

ADP Example:

The total raw gas production for the month of January 2009 is 233.6 10^3m^3, and the total production hours are 512. The ADP is calculated as follows:

ADP = (233.6 / 512) * 24
ADP = 0.45625 * 24
ADP = 10.95 10^3m^3/day

Acid Gas Factor = AGF (Adjustment to the ADP)

The AGF is a factor that adjusts the ADP of a well event if that well event is producing high amounts of acid gas, that is, if the combined concentration of hydrogen sulphide (H_2S) and carbon dioxide (CO_2) is greater than 3% and less than or equal to 25%. If a well event has an acid gas content of less than or equal to 3%, then the AGF of the well event will default to 1.00. If a well event has acid gas content greater than 25% then the AGF has a minimum value of 0.78.

The AGF is determined based on the following formula:

AGF = [1.03 – (H_2S% + CO_2%)]

The ADP is adjusted by multiplying the ADP by the AGF, that is:

Adjusted ADP = ADP * AGF

The acid gas content of a well event, used by the department for the determination of the AGF, will be according to the records of the ERCB.

AGF Example:
If a well event has the following concentrations for hydrogen sulphide and carbon dioxide, according to the records of the ERCB:

H_2S = 4%, and
CO_2 = 5%.

Then the AGF is calculated as follows:

AGF = [1.03 – (H_2S % + CO_2%)]
= [1.03 – (0.04 + 0.05)]
= [1.03 – 0.09]
= 0.94

Using the information provide in the previous ADP example, above, where the ADP = 10.95 103m3/day, then:

Adjusted ADP = ADP * AGF
= 10.95 * 0.94
= 10.293 $10^3 m^3$/day

2.2.2.2 DF = Depth Factor

A depth factor (DF) is required for all well events, and is calculated based on the measured depth (MD) according to the records of the ERCB for that well event.

Information on the MD, of a well event, can be found on the Petroleum Registry of Alberta (PRA) in the ‘Infrastructure’ section per the following screen shots:

Figure 2.2.2.2.1 PRA Screen – Query MD

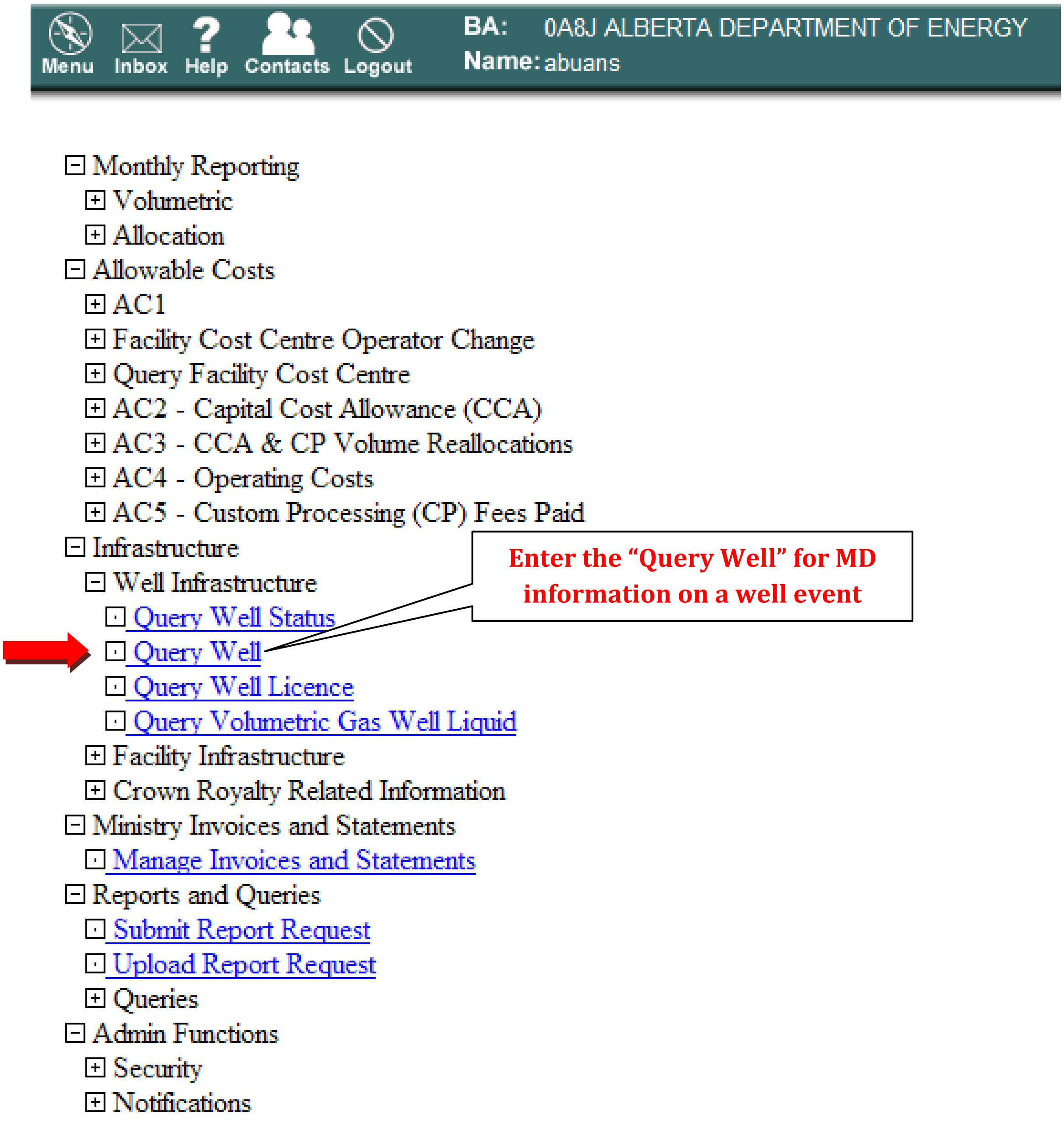
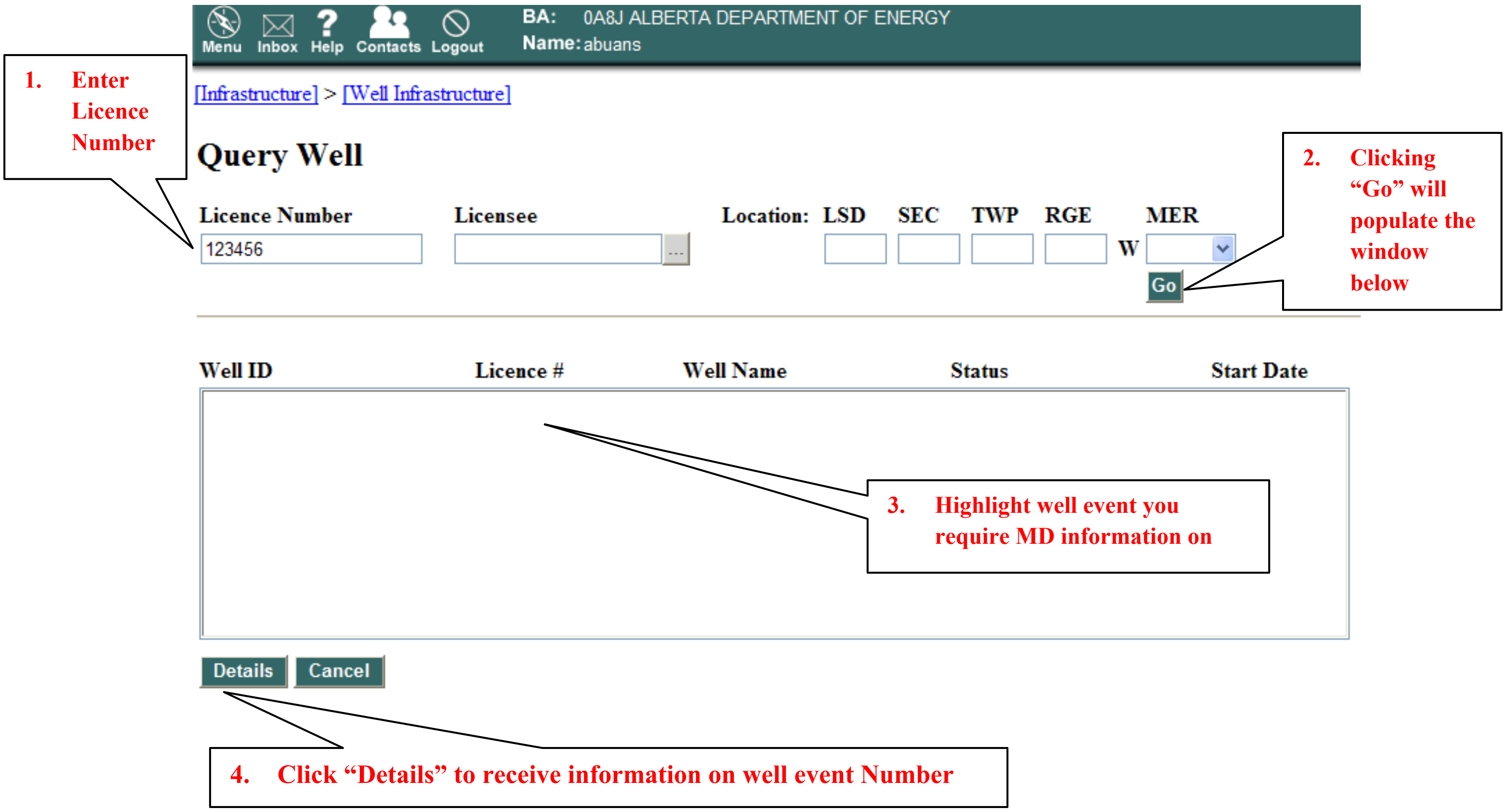


Figure 2.2.2.2.2 PRA Screen – Query MD



The DF is used in the determination of the quantity component (r_q) of the royalty rate; it adjusts the quantity component royalty formula for measured depths that exceed 2000 metres.

The DF for a well event is determined based on the following formula:

$$\mathbf{DF} = \left(\frac{\mathbf{MD}}{\mathbf{2000}}\right)^{2}$$

A well event with a MD greater than 2,000 metres will receive a royalty adjustment based on production from the well event. A well event without a reported MD or with MD less than or equal to 2,000 metres will have a DF of 1.00. The DF is capped at 4.00 for well events with MD greater than or equal to 4,000 metres.

$$\textbf{If the MD is} \begin{cases} \leq 2{,}000 \text{ metres then the DF} = 1.00 \\ > 2{,}000 \text{ metres and} < 4{,}000 \text{ metres then DF} = \left(\dfrac{\text{MD}}{2000}\right)^{2} \\ \geq 4{,}000 \text{ metres then the DF} = 4.00 \end{cases}$$

There may be situations where the MD for a well event changes such as when a deeper zone or interval is brought on production. Changes to the MD are to be reported by Industry through the PRA, the department will apply these changes on a go forward basis. All MD amendments are subject to review by the ERCB and department. If a royalty client requires that the MD be retroactively changed then a written request must be submitted to Gas Royalty Calculation.

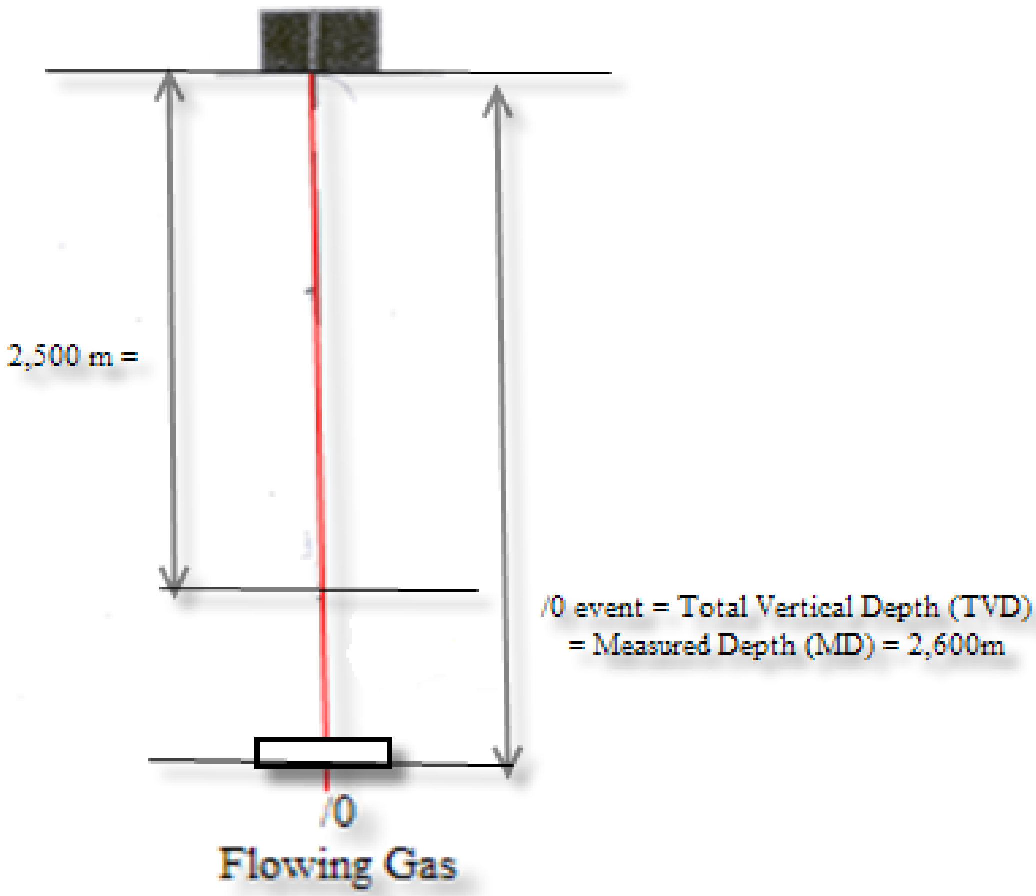
The MD, for a well event, is based upon information provided by the well operator and submitted to the ERCB. The MD is defined as:

- For a well event the MD is the longest distance, in metres, along the bore of the well from the kelly bushing of the well containing the well event to the bottom of the gross completion interval (GCI) from which the well event is producing.
- A well with one producing well event and one or more well events that are given a status of drain by the ERCB, will then have a MD that is the sum of (a) and (b):
  - (a) The length, in metres, of the producing well event from the kelly bushing of the well to the bottom of the GCI, and
  - (b) The sum of the lengths, in metres, of all the drains contributing to the producing well event's production, where the length of a drain is between the last kick-off point of the drain (leg or well bore) and end of each corresponding drain only once, i.e. bottom of each drains GCI.

The following are examples to illustrate the calculation of the depth factor (DF):

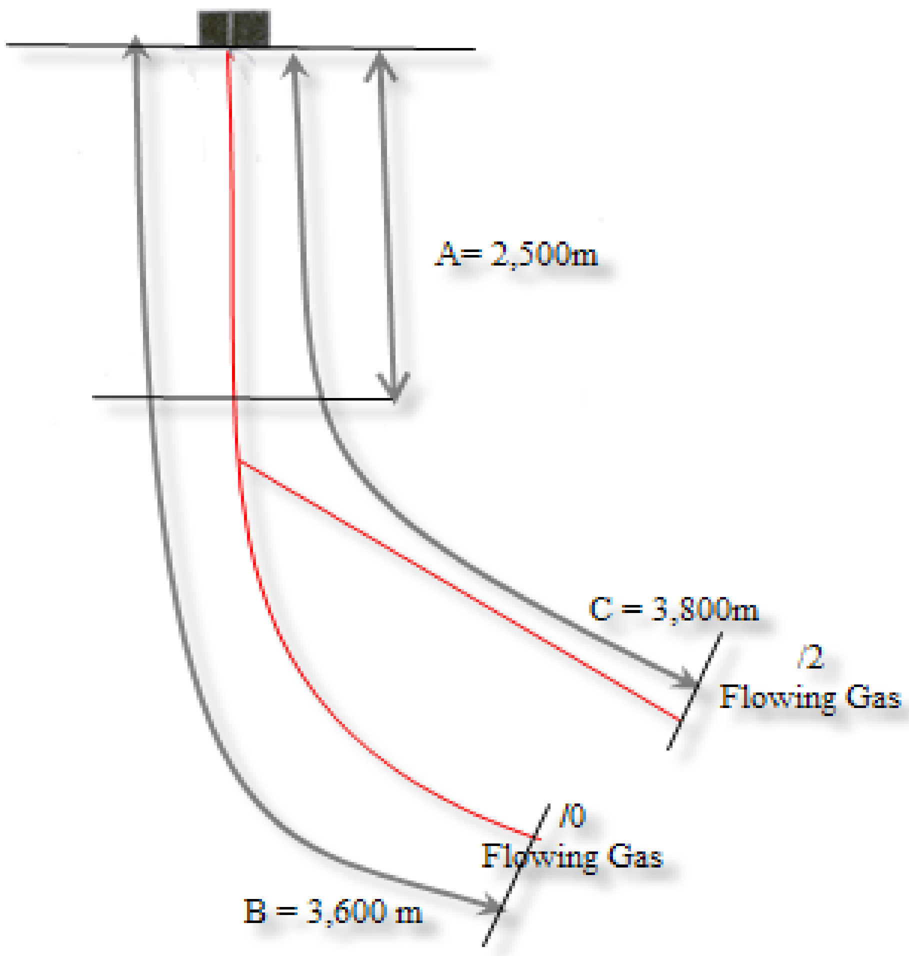
Example 1:
For a well with only one drilling occurrence, the /0 well event, has a flowing gas status, and a measured depth of 2,600 metres. The DF calculation is as follows:

$$DF = (2{,}600/2{,}000)^2$$
$$= (1.30)^2$$
$$= 1.69$$

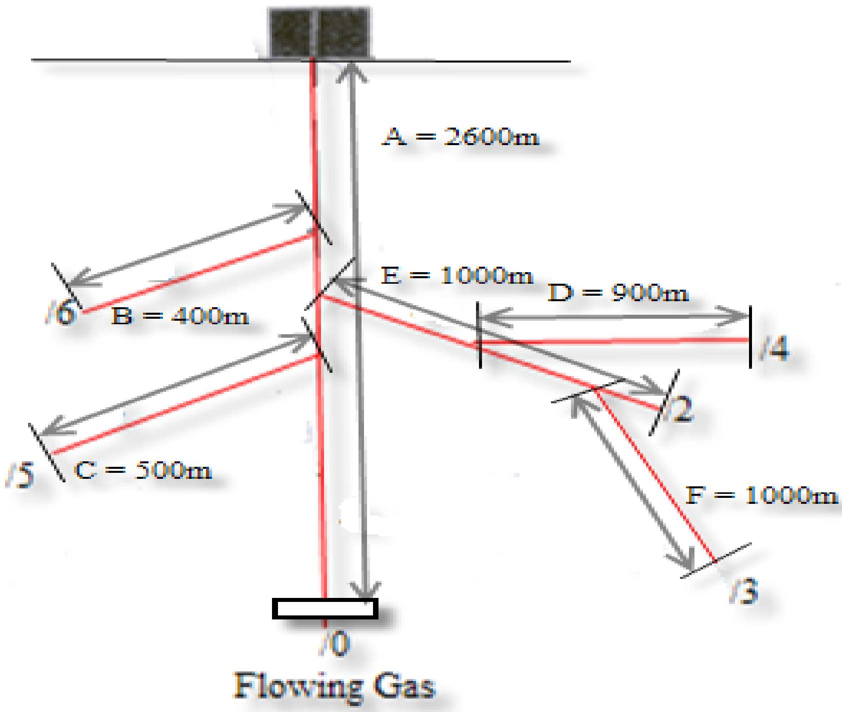


Example 2:
For a well with two drilling occurrences each of which is a separately identified well event, as seen below the /0 event and /2 event. Both well events have a flowing gas status, with a MD of 3,600 metres for the /0 event and 3,800 metres for the /2 event. Each well event will be assigned its own DF based on the following calculations:

/0 event:	**/2 event:**
MD = 3,600 m (length 'B') DF = $(3{,}600/2{,}000)^2$ = 1.80^2 = 3.24	MD = 3,800 m (length 'C') DF = $(3{,}800/2{,}000)^2$ = 1.90^2 = 3.61



Example 3:
For a well that has 6 well events, where the /0 well event is the only event where there is production (reported as flowing gas status to the ERCB) and the remainder of the well events are reported as drain status. The DF calculation is as follows:



Well Event	Status	Total Depth (1)[1]	Kickoff Point (2)[2]	Length of leg [for drains = (1) – (2)][3]	Identifier (see chart below)
/0	Producing	2,600	-	2,600	A
/2	Drain	2,500	1,500	1,000	E
/3	Drain	3,000	2,000	1,000	F
/4	Drain	2,700	1,800	900	D
/5	Drain	2,900	2,400	500	C
/6	Drain	1,600	1,200	400	B
MD				6,400[4]	

Notes:
1. The total depth is the measured length from the kelly bushing to the bottom of the producing zone for a well event, whether producing or drain
2. The kickoff point is the distance from the kelly bushing to the deviation for the leg/drain e.g. leg B of well event /6, deviates from the main bore hole at 1,200 metres
3. The length of the leg results from subtracting the last kickoff measurement from the total depth length,
4. The sum of the individual leg lengths determines the MD, that is, MD = A+B+C+D+E+F

MD =6,400 metres
DF = $(6,400/2,000)^2$
DF = $(3.20)^2$
DF = 10.24, the DF is capped at 4.00 for this well event.

Example 4:
If any of the well events in the above example are abandoned, that is they do not contribute to the production of the flowing gas well event, then its leg length is not included in the MD.
If the /3 well event is abandoned then its 1,000 metres of length (F) is not included in the MD thus the
MD = A+B+C+D+E = 2,600+400+500+900+1,000 = 5,400 metres

2.2.2.3 Quantity Component Calculation

Determination of the quantity component of the new royalty formula uses the ADP, AGF and DF as per the previous 2 sections and is based upon the following table:

Table 2.2.2.3.1 - Quantity Component (r_q)

Quantity ($10^3m^3/d$)	**r_q**
ADP≤ (6 * DF)	[ADP – (4 * DF)] * (0.0500/DF) (1)
(6 * DF) < ADP ≤ (11* DF)	[ADP – (6 * DF)] * (0.0300/DF) + 0.1000[A] (2)
ADP > (11* DF)	[ADP – (11 * DF)] * (0.0100/DF) + 0.2500[B] (3)
Maximum	30%
Minimum	Can be negative

Note:
A. 0.1000 in equation (2) occurs when the ADP = (6 * DF) for equation (1), regardless of what the DF is. For example if the DF = 1 then Equation (1) becomes
= [(6 * 1) - (4 * 1)]*(0.0500/1)
= [6 - 4]*(0.0500)
= 2 * (0.0500)
= 0.1000

B. 0.2500 in equation (3) occurs when the ADP = (11 * DF) for equation (2), regardless of what the DF is. For example if the DF = 1 then Equation (2) results in:
= [(11 * 1) - (6 * 1)]*(0.0300/1) + 0.1000
= [11 - 6]*(0.0300) + 0.1000
= 5 * 0.0300 + 0.1000
= 0.1500 + 0.1000
= 0.2500

The ADP is determined based on the raw gas production of a well event therefore both the methane and ethane quantity component (r_q) royalty rates will have the same r_q%.

If the DF = 1 (i.e. the MD is less than or equal to 2,000 metres) this adjusts the above table as follows:

Table 2.2.2.3.2 - Quantity Component with a DF = 1

Quantity (10^3m^3/d)	**r_q**
ADP≤ 6	[ADP – 4] * (0.0500) (1)
6 < ADP ≤ 11	[ADP – 6] * (0.0300) + 0.1000 (2)
ADP > 11	[ADP – 11] * (0.0100) + 0.2500 (3)
Maximum	30%
Minimum	Can be negative

If the MD for a well event is greater than 2,000 metres this results in a DF that is greater than one which adjusts Table 2.2.2.3.1. For example, if the MD for a well event is 3,200 metres, the DF = 2.56, then table 2.2.2.3.1 is adjusted as follows:

Table 2.2.2.3.3 - Quantity Component with a DF = 2.56

Quantity (10^3m^3/d)	**r_q**
ADP≤ 15.36	[ADP – 10.24] * (0.01953) (1)
15.36 < ADP ≤ 28.16	[ADP – 15.36] * (0.01172) + 0.1000 (2)
ADP > 28.16	[ADP – 28.16] * (0.00391) + 0.2500 (3)
Maximum	30%
Minimum	Can be negative

The following are examples to illustrate the calculation of the quantity component rate (r_q%):

Example 1:
For a well event that reports the following:
Raw gas production: 112 10^3m^3 for the month
Hours on production: 744 hours for the month
MD of the well event: 1,929 metres
CO_2 content: 1.00%
H_2S content: 0.05%

AGF: CO_2 + H_2S
= 1.00% + 0.05%
= 1.05%, since the AGF is ≤ 3% the ADP for this well event is not adjusted.
ADP: = (112/744)*24
= 3.6129 10^3m^3/day
DF: = 1.00, since MD ≤ 2,000 metres

Since the DF = 1 the quantity component royalty rate is based on Table 2.2.2.3.2, and with the ADP = 3.6129 10^3m^3/day use equation (1) from this table to determine the r_q%, as follows:

$$
\begin{aligned}
r_q &= [ADP - 4] * (0.0500) \\
&= [3.6129 - 4] * (0.0500) \\
&= (-0.3871) * 0.0500 \\
&= -0.019355
\end{aligned}
$$

Both methane and ethane will have the same quantity component royalty rate (r_q%) of -1.9355%.

Example 2:

For a well event that reports the following:

Raw gas production:	490 10^3m^3 for the month
Hours on production:	600 hours for the month
MD of the well event:	1,929 metres
CO_2 content:	1.00%
H_2S content:	0.05%

AGF: $CO_2 + H_2S$
= 1.00% + 0.05%
= 1.05%, since the AGF is ≤ 3% the ADP for this well event is not adjusted.

ADP: = (490/600)*24
= 19.6 10^3m^3/day

DF: = 1.00, since MD ≤ 2,000 metres

Since the DF = 1 the quantity component royalty rate is based on Table 2.2.2.3.2, and with the ADP = 19.6 10^3m^3/day use equation (3) from this table to determine the rq%, as follows:

$$
\begin{aligned}
r_q &= [ADP - 11]*(0.0100) + 0.2500 \\
&= [19.6 - 11]*(0.0100) + 0.2500 \\
&= [8.6]*(0.0100) + 0.2500 \\
&= 0.086 + 0.2500 \\
&= 0.3360
\end{aligned}
$$

Both methane and ethane will have the same quantity component royalty rate (r_q%) of 30%, since the rate is capped.

Example 3:

For a well event that reports the following:

Raw gas production:	490 10^3m^3 for the month
Hours on production:	600 hours for the month
MD of the well event:	2,900 metres
CO_2 content:	0.95%
H_2S content:	1.50%

AGF: $CO_2 + H_2S$
= 0.95% + 1.50%
= 2.45%, since the AGF is ≤ 3% the ADP for this well event is not adjusted.

ADP: = (490/600)*24
= 19.6 10^3m^3/day

DF: = $(2,900/2,000)^2$
= $(1.45)^2$
= 2.1025, since MD > 2,000 metres this adjusts Table 2.2.2.3.1 as follows:

Quantity (10^3m^3/d)	**r_q**
ADP≤ 12.615	[ADP – 8.41] * (0.02378) (1)
12.615 < ADP ≤ 23.1275	[ADP – 12.6150] * (0.01427) + 0.1000 (2)
ADP > 23.1275	[ADP – 23.1275] * (0.00476) + 0.2500 (3)
Maximum	30%
Minimum	Can be negative

With the ADP = 19.6 10^3m^3/day use equation (2) in the table above to determine the r_q%, as follows:

r_q = [ADP – 12.6150] * (0.01427) + 0.1000
= [19.6 – 12.6150] * (0.01427) + 0.1000
= 6.985 * (0.01427) + 0.1000
= 0.09968 + 0.100
= 0.19968

Both methane and ethane will have the same quantity component royalty rate (r_q%) of 19.968%.

Example 4:
For a well event that reports the following:

Raw gas production:	490 10^3m^3 for the month
Hours on production:	600 hours for the month
MD of the well event:	2,900 metres
CO_2 content:	7.00%
H_2S content:	8.00%

AGF: $CO_2 + H_2S$
= 7.00% + 8.00%
= 15.00%, since the AGF is > 3% the ADP for this well event will be adjusted by the following factor
AGF = $[1.03 – (H_2S \% + CO_2\%)]$
= [1.03 – (0.15)]
= 0.88

ADP: = (490/600)*24
= 19.6 10^3m^3/day
Adjusted ADP = ADP * AGF
= 19.60 * 0.88
= 17.248 10^3m^3/day

DF: = $(2{,}900/2{,}000)^2$
= $(1.45)^2$
= 2.1025, since MD > 2,000 metres this adjusts Table 2.2.2.3.1 as follows:

Quantity (10^3m^3/d)	**r_q**	
ADP≤ 12.615	[ADP – 8.41] * (0.02378)	(1)
12.615 < ADP ≤ 23.1275	[ADP – 12.6150] * (0.01427) + 0.1000	(2)
ADP > 23.1275	[ADP – 23.1275] * (0.00476) + 0.2500	(3)
Maximum	30%	
Minimum	Can be negative	

With the ADP = 17.248 10^3m^3/day use equation (2) in the table above to determine the r_q%, as follows:

r_q = [ADP – 12.6150] * (0.01427) + 0.1000
= [17.248 – 12.6150] * (0.01427) + 0.1000
= 4.633 * (0.01427) + 0.1000
= 0.06611 + 0.100
= 0.16611

Both methane and ethane will have the same quantity component royalty rate (r_q%) of 16.611%.

2.2.3 Total Royalty Rate (R%)

For a well event the total royalty rate (R%), for methane and ethane, is the sum of the price component (r_p%) and the quantity component (r_q%), that is:

$$R\% = r_p\% + r_q\%.$$

Example:

The following illustrates the calculation of the total royalty rate for a well event:

Calculation of price component rate:
If the PP, as determined and published by the department, is as follows:

Methane ISC PP:	\$6.60/GJ
Ethane ISC PP:	\$4.00/GJ

Then r_p is calculated as follows:

Methane:	$r_{p\ methane}\% = 9.45\%$ *(see Section 2.2.1 Example 1 for details)*
Ethane:	$r_{p\ ethane}\% = -2.25\%$ *(see Section 2.2.1 Example 2 for details)*

Calculation of quantity component rate:
For a well event that reports the following:

Raw gas production:	112 10^3m^3 for the month
Hours on production:	744 hours for the month
MD of the well event:	1,929 metres
CO_2 content:	1.00%
H_2S content:	0.05%

Then r_q for this well event is -1.9355
(Reproduction from example 1, section 2.2.2.3)

Total royalty rate for methane:

$R_{methane}\% = r_{p\ methane}\% + r_q\%$
$= 9.45\% + -1.9355$
$= 7.5145\%$

For this well event the total royalty rate (R%) charged to methane is 7.5145%.

Total royalty rate for ethane:

$R_{ethane}\% = r_{p\ ethane}\% + r_q\%$
$= -2.25\% + -1.9355\%$
$= -4.1855\%$

For this well event the total royalty rate (R%) charged to ethane is 5%, since this is the minimum total royalty rate allowed.

For this well event the other ISCs are charged the following fixed rates:

Propane ISC:	30%
Butanes ISC:	30%
Pentanes Plus ISC:	40%

2.3 Solution Gas

Solution gas is defined for royalty purposes as the gaseous component found in conventional crude oil or bitumen that is separated from the crude oil or bitumen after recovery from a well event. Solution gas will continue to be treated the same as natural gas, with the exception that the ADP will be based upon the well event total production of both the solution gas and the gas equivalent energy content of conventional oil or bitumen. Solution gas royalty calculation follows the natural gas royalty calculation as illustrated on section 2.2. Conversion factor from oil or bitumen into gas equivalent energy is 1.0686 10^3 m^3 of natural gas per m^3 of crude oil.

Example:

The following illustrates the calculation of the total royalty rates for a well event (R%) with solution gas:

Calculation of price component rate:
If the PP, as determined and published by the department, is as follows:
Methane ISC PP: $6.60/GJ
Ethane ISC PP: $4.00/GJ

Then r_p is calculated as follows:
Methane: $r_{p\ methane}$% = 9.45% (see per the example on the previous page)
Ethane: $r_{p\ ethane}$% = -2.25% (see per the example on the previous page)

Calculation of quantity component rate:
For a well event that reports the following:

Raw gas production:	112 $10^3 m^3$ for the month
Oil production:	97.60 m^3 for the month
Hours on production:	744 hours for the month
MD of the well event:	1,929 metres
CO_2 content:	1.00%
H_2S content:	0.05%

AGF: $CO_2 + H_2S$
= 1.00% + 0.05%
= 1.05%, since the AGF is ≤ 3% the ADP for this well event is not adjusted.

DF: = 1.00, since MD ≤ 2,000 metres

ADP: Conversion of Oil Volumes to Energy Adjusted Gas Volumes:
= 97.60 m^3 * 1.0686
= 104.295 10^3 m^3

This converted oil volume is added to the gas volume to equal the total well event raw gas volume for the determination of ADP:
= 104.295 10^3 m^3 + 112.0 10^3 m^3
= 216.295 10^3 m^3

Therefore the determination of the ADP for methane and ethane quantity component royalty rates is:

$ADP = (216.295 /744)*24$
$= 6.977\ 10^3 m^3/day$

Since the DF = 1 the quantity component royalty rate is based on Table 2.2.2.3.2, and with the ADP = 6.977 $10^3 m^3$/day use equation (2) from this table to determine the r_q%, as follows:

$r_q = [ADP – 6] * (0.0300) + 0.1000$
$= [6.977 – 6] * (0.0300) + 0.1000$
$= [0.977] * (0.0300) + 0.1000$
$= 0.02931 + 0.1000$
$= 0.12931$

Both methane and ethane will have the same quantity component royalty rate (r_q%) of 12.931%.

Total royalty rate for methane:

$R_{methane}\% = r_{p\ methane}\% + r_q\%$
$= 9.45\% + 12.931\%$
$= 22.381\%$

For this well event the total royalty rate (R%) charged to methane is 22.381%.

Total royalty rate for ethane:

$R_{ethane}\% = r_{p\ ethane}\% + r_q\%$
$= -2.25\% + 12.931\%$
$= 10.681\%$

For this well event the total royalty rate (R%) charged to ethane is 10.681%.

For this well event the other ISCs are charged the following fixed rates:

Propane ISC:	30%
Butanes ISC:	30%
Pentanes Plus ISC:	40%

2.4 Field Condensate

For Crown royalty purposes, field condensate is defined as "products obtained from natural gas or solution gas before they are delivered to a gathering system". Typically, field condensate is separated from gas in the field and sold or otherwise disposed of without further processing before entering a gas gathering system.

The determination of the royalty rate for field condensate is based on the conventional oil royalty formula. The total calculated royalty rate for condensate will be the sum of the price and quantity components, where the price component (r_p) is based on the par price of pentanes plus and the quantity component (r_q) is based on total monthly production of both the field condensate and field condensate equivalent energy content of the gas (conversion factor from gas into field condensate equivalent volume is 0.78783 10^3 m^3 of natural gas per m^3 of condensate). The quantity component of the conventional oil royalty formula is based on the total monthly production for a well event while for a natural gas well event the quantity component utilizes an ADP (calculated from the total monthly production and the hours on).

2.4.1 Price Component (r_p):

The price component of the new conventional oil royalty formula is determined by the monthly pentanes plus par price as per the following table:

Table 2.4.1.1 - Conventional Oil Price Component (r_p)

Price ($/m3)	r_p
PP ≤ 250.00	(PP – 190.00) * 0.0006
250.00 < PP ≤ 400.00	(PP – 250.00) * 0.0010 + 0.0360[A]
PP > 400.00	(PP – 400.00) * 0.0005 + 0.1860[B]
Maximum	35%
Minimum	Can be negative

Note:

A. Where 0.0360 = (PP – 190.00) * 0.0006 at its maximum value of PP = 250.00
⇨ (250.00 – 190.00) * 0.0006 = 60 * 0.0006 = 0.0360

B. Where 0.1860 = (PP – 250.00) * 0.0010 + 0.0360 at its maximum value of PP=400.00
⇨ (400.00 – 250.00) * 0.0010 + 0.0360 = 150.00 * 0.0010 + 0.0360 = 0.1860

Where the parameters identified in the table above are defined as follows:

PP = Par Price

The PP of pentanes plus is used to determine the price component (r_p) of field condensate. The PP is a provincial weighted price determined by the department and published in its Information Letter for each production month. Determination of the PP has not changed under NRF.

The following are examples to illustrate the calculation of the price component rate (r_p%) for field condensate:

Example 1:

If the PP, as determined and published by the department, for pentanes plus is $150.00/$m^3$, then r_p is calculated as follows:

Since the PP of $150.00/$m^3$is less than $250.00/$m^3$, r_p is calculated using the equation in the first row of Table 2.4.1.1, as follows:

$$\begin{aligned} r_p &= (PP - 190.00) * 0.0006 \\ &= (150.00 - 190.00) * 0.0006 \\ &= -40.00 * 0.0006 \\ &= -0.024 \end{aligned}$$

The r_p for field condensate for this production month is -2.40%, this negative rate is acceptable as the price component can be negative.

Example 2:
If the PP, as determined and published by the department, for pentanes plus is \$225.00/m^3, then r_p is calculated as follows:

Since the PP of \$225.00/$m^3$is less than \$250.00/m^3, r_p is calculated using the equation in the first row of Table 2.4.1.1, as follows:

$$
\begin{aligned}
r_p &= (PP - 190.00) * 0.0006 \\
&= (225.00 - 190.00) * 0.0006 \\
&= 35.00 * 0.0006 \\
&= 0.021
\end{aligned}
$$

The price component rate for field condensate for this production month is 2.10%.

Example 3:
If the PP, as determined and published by the department, for pentanes plus is \$360.00/m^3, then r_p is calculated as follows:

Since the PP of \$360.00/$m^3$is greater than \$250.00/m^3 and less than \$400.00/m^3, r_p is calculated using the equation in the second row of Table 2.4.1.1, as follows:

$$
\begin{aligned}
r_p &= (PP - 250.00) * 0.0010 + 0.0360 \\
&= (360.00 - 250.00) * 0.0010 + 0.0360 \\
&= 110.00 * 0.0010 + 0.0360 \\
&= 0.110 + 0.0360 \\
&= 0.1460
\end{aligned}
$$

The price component rate for field condensate for this production month is 14.60%.

Example 4:
If the PP, as determined and published by the department, for pentanes plus is \$945.00/m^3, then r_p is calculated as follows:

Since the PP of \$945.00/$m^3$is greater than \$400.00/m^3, r_p is calculated using the equation in the third row of Table 2.4.1.1, as follows:

$$
\begin{aligned}
r_p &= (PP - 400.00) * 0.0005 + 0.1860 \\
&= (945.00 - 400.00) * 0.0005 + 0.1860 \\
&= 545.00 * 0.0005 + 0.1860 \\
&= 0.2725 + 0.1860 \\
&= 0.4585
\end{aligned}
$$

The price component rate for field condensate for this production month is capped at its maximum of 35%.

2.4.2 Quantity Component (r_q):

The quantity component for field condensate uses the new conventional oil royalty formula. The quantity component of the oil formula requires a total monthly production (Q), that is the sum of monthly production of both the field condensate and field condensate equivalent energy content of the gas (conversion factor from gas into field condensate equivalent volume is 0.78783).

Table 2.4.2.1 - Conventional Oil Quantity Component (r_q)

Quantity (m^3/month)	r_q	
$Q \leq 106.4$	(Q – 106.4) * 0.0026	(1)
$106.4 < Q \leq 197.6$	(Q – 106.4) * 0.0010	(2)
$197.6 < Q \leq 304.0$	(Q – 197.6) * 0.0007 + 0.0912[A]	(3)
$Q > 304.0$	(Q – 304.0) * 0.0003 + 0.1657[B]	(4)
Maximum	30%	
Minimum	Can be negative	

Note:
A. Where 0.0912= (Q – 106.4) * 0.0010 at its maximum value of Q = 197.6
⇨ (197.6 – 106.4) * 0.0010 = 91.2 * 0.0010 = 0.0912
B. Where 0.1657= (Q – 197.6) * 0.0007 + 0.0900 at its maximum value of Q = 304.0
⇨ (304.0 – 197.6) * 0.0007 + 0.0912 = 106.4 * 0.0007 + 0.0912 = 0.1657

Where the parameters identified in the table above are defined as follows:

Q = Monthly production (m^3)
This is the total monthly production of both the field condensate (report as a liquid in m^3) and the field condensate equivalent energy content of the gas, that is, the raw gas production converted to the field condensate equivalent volume (converted by a factor of 0.78783).

For example, the well operator reports that the total raw gas production for the month is 900 10^3 m^3 and the total field condensate production for the same month is reported as 20 m^3.

Convert the raw gas production to a condensate equivalent volume, as follows:

= 900 10^3 m^3 / 0.78783
= 1,142.378 m^3

Add the amount from above to the field condensate liquid volume to determine the total monthly production (Q) for the well event:

Q = 1,142.378 m3 + 20 m3
= 1,162.378 m3,

This total liquid amount is used in Table 2.4.2.1 to determine the r_q.

The following are examples to illustrate the calculation of the quantity component rate (r_q) for field condensate production:

Example 1:
For a well event that reports the following:
Raw gas production: 47.00 $10^3 m^3$ for the month
Field condensate production: 21.0 m^3 for the month

Convert the raw gas production to a condensate equivalent volume, as follows:
$$= 47.00\ 10^3\ m^3 / 0.78783 = 59.6575\ m^3$$

Add the above amount to the field condensate production to determine Q:
$$Q = 59.6575\ m^3 + 21.0\ m^3 = 80.6575\ m^3$$

Since Q for this well event is less than 106.4, use equation (1) of Table 2.4.2.1 to determine the r_q, as follows:
$$\begin{aligned} r_q &= (Q – 106.4) * 0.0026 \\ &= (80.6575 – 106.4) * 0.0026 \\ &= -25.7425 * 0.0026 \\ &= -0.06693 \end{aligned}$$
The quantity component rate for field condensate for this production month is -6.693%.

Example 2:
For a well event that reports the following:
Raw gas production: 105.00 $10^3 m^3$ for the month
Field condensate production: 32.0 m^3 for the month

Convert the raw gas production to a condensate equivalent volume, as follows:
= 105.00 103 m3 / 0.78783 = 133.2775 m3

Add the above amount to the field condensate production to determine Q:
$$Q = 133.2775\ m^3 + 32.0\ m^3 = 165.2775\ m^3$$

Since Q for this well event is less than 197.6 and greater than 106.4, use equation (2) of Table 2.4.2.1 to determine the r_q, as follows:
$$\begin{aligned} r_q &= (Q – 106.4) * 0.0010 \\ &= (165.2775 – 106.4) * 0.0010 \\ &= 58.8775 * 0.0010 \\ &= 0.05888 \end{aligned}$$
The quantity component rate for field condensate for this production month is 5.888%.

Example 3:
For a well event that reports the following:

Raw gas production:	216.00 10^3m^3 for the month
Field condensate production:	12.0 m^3 for the month

Convert the raw gas production to a condensate equivalent volume, as follows:

$$= 216.00\ 10^3\ m^3 / 0.78783 = 274.1708\ m^3$$

Add the above amount to the field condensate production to determine Q:

$$Q = 274.1708\ m^3 + 12.0\ m^3 = 286.1708\ m^3$$

Since Q for this well event is less than 304.0 and greater than 197.6, use equation (3) of Table 2.4.2.1 to determine the r_q, as follows:

$$\begin{aligned} r_q &= (Q - 197.6) * 0.0007 + 0.0900 \\ &= (286.1708 - 197.6) * 0.0007 + 0.0912 \\ &= 88.5708 * 0.0007 + 0.0912 \\ &= 0.06200 + 0.0912 \\ &= 0.1532 \end{aligned}$$

The quantity component rate for field condensate for this production month is 15.32%.

Example 4:
For a well event that reports the following:

Raw gas production:	1,256.44 10^3m^3 for the month
Field condensate production:	57.40 m^3 for the month

Convert the raw gas production to a condensate equivalent volume, as follows:

$$= 1{,}256.44\ 10^3\ m^3 / 0.78783 = 1{,}594.811\ m^3$$

Add the above amount to the field condensate production to determine Q:

$$Q = 1{,}594.811\ m^3 + 57.4\ m^3 = 1{,}652.2111\ m^3$$

Since Q for this well event is greater than 304.0, use equation (4) of Table 2.4.2.1 to determine the r_q, as follows:

$$\begin{aligned} r_q &= (Q - 304.0) * 0.0003 + 0.1600 \\ &= (1{,}652.2111 - 304.0) * 0.0003 + 0.1657 \\ &= 1{,}348.2111 * 0.0003 + 0.1657 \\ &= 0.4045 + 0.1657 \\ &= 0.5702 \end{aligned}$$

The quantity component rate for field condensate for this production month is capped at its maximum of 30%.

2.5 Well Event Average Royalty Rate (WEARR)

The new royalty framework requires the determination of a royalty rate at the well event. Under the current royalty regime a Facility Average Royalty Rate (FARR) and Raw Gas Average Royalty Rate (RARR) are used to determine royalty rates – these will be replaced by the WEARR.

The Well Event Average Royalty Rate (WEARR) is a weighted average, at the well event, of the individual ISC product royalty rates, weighted by the ISC composition of the gas stream based on information available at the point of royalty determination.

The weighting of the ISC composition of the gas stream at the facility will employ a Facility Component Proportion (FCP), which is the ratio of the heat content of individual ISC products to the total heat content of the gas disposition reported at the point of royalty determination, referred to as a royalty trigger facility.

The Facility Component Proportion of ISC products are used to determine the gas composition of all well events that receive allocations from the triggered facility. ISC is reported for each product component at the royalty trigger facility(s) and is required to balance back to the meter station. If the ISC is out of balance between the royalty trigger facility(s), the product that is out of balance will be assessed at the pentanes plus royalty rate of 40% and pentanes plus ISC reference price.

2.5.1 Single Well Event WEARR Calculation

The following is an example to illustrate the determination and calculation of royalties for a single well event:

The Par Price, as determined and published by the department, is as follows:
Methane ISC PP: $6.66/GJ
Ethane ISC PP: $7.20/GJ

Then r_p% is calculated as follows, using Table 2.2.1.1 Price Component (r_p):
Methane: $r_{p\ methane}\%$ = 9.72%
Ethane: $r_{p\ ethane}\%$ = 11.85%

For a well event that reports the following:

Raw gas production:	604.50 10^3m^3 for the month
Total heat:	17, 552.39 GJ for the month
Hours on production:	744 hours for the month
MD of the well event:	1,929 metres
CO_2 content:	1.00%
H_2S content:	0.05%

Calculation of quantity component rate:

AGF: $CO_2 + H_2S$
= 1.00% + 0.05%
= 1.05%, since the AGF is ≤ 3% the ADP for this well event is not adjusted.

DF: = 1.00, since MD ≤ 2,000 metres

ADP = (604.50 /744)*24
= 19.50 10^3m^3/day

Since the DF = 1 the quantity component royalty rate is based on Table 2.2.2.3.2, and with the ADP = 19.50 10^3m^3/day use equation (3) from this table to determine the r_q%, as follows:

r_q = [ADP – 11] * (0.0100) + 0.2500
= [19.50 – 11] * (0.0100) + 0.2500
= [8.5 * 0.0100] + 0.2500
= 0.0850 + 0.2500
= 0.3350

Both methane and ethane will have the same quantity component royalty rate, r_q%, of 30%, as the calculated r_q exceeds the maximum allowable.

Total royalty rate for methane:

$R_{methane}\% = r_{p\ methane}\% + r_q\%$
= 9.72% + 30%
= 39.72%

For this well event the total royalty rate (R%) charged to methane is 39.72%.

Total royalty rate for ethane:

$R_{ethane}\% = r_{p\ ethane}\% + r_q\%$
= 11.85% + 30%
= 41.85%

For this well event the total royalty rate (R%) charged to ethane is 41.85%.

For this well event the other ISCs are charged the following fixed rates:

Propane ISC:	30%
Butanes ISC:	30%
Pentanes Plus ISC:	40%

If the heat content of methane ISC, ethane ISC, propane ISC, butanes ISC, and pentanes plus ISC 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 FCP method is used to determine WEARR for a well event.

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:

Table 2.5.1.1 - Reported Facility In-stream Components (ISCs)

Product ISC (1)	Volume ($10^3 m^3$) (2)	Heat (GJ) (3)	FCP (4) = (3)/(sum of all ISCs)
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%

Note:
*A. 81.5798% = 88,161.652 / 108,068.000 * 100*

In the above table 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 108,068.000 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:

Table 2.5.1.2 - Well Event FCP Calculated ISCs

Product (1)	Total Well Event Heat (2)	Calculated Facility FCP *(column (4) Table2.5.1.1)* (3)	Well Event (GJ) *= (2) * (3)* (4)
C1-IC	17,552.39	81.5798 %	14,319.2036
C2-IC	17,552.39	11.3606 %	1,994.0569
C3-IC	17,552.39	5.0110 %	879.5513
C4-IC	17,552.39	1.6419 %	288.1955
C5-IC	17,552.39	0.4067 %	71.3826
Total		100.00 %	17,552.3900

The WEARR is the weighted average royalty rate for the well event where the weightings are based upon the individual heat content of the in-stream components. Calculations are completed based on the following table:

Table 2.5.1.3 - WEARR Calculation

Product **(1)**	**Heat content (GJ)** *(column (4) Table2.5.1.2)* **(2)**	**ISC Calculated Royalty Rate** **(3)**	**Royalty Heat (GJ)** *= (2) * (3)* **(4)**
C1-IC	14,319.2036	39.72 %	5,687.5877
C2-IC	1,994.0569	41.85 %	834.5128
C3-IC	879.5513	30 %	263.8654
C4-IC	288.1955	30 %	86.4587
C5-IC	71.3826	40 %	28.5530
Total	**17,552.3900 GJ (6)**		**6,900.9776 GJ (5)**

WEARR = Royalty heat (GJ) for the well event / Total heat content (GJ) of the well
= (5) / (6)
= 6,900.9776 / 17,552.3900 * 100
= 39.3165%

The WEARR of 39.3165% is applied to the total heat content of the well to determine the crown heat

2.5.2 Solution Gas' WEARR Calculation

Solution gas will continue to be treated the same as natural gas, with the exception that the ADP will be based upon the well event total production of both the solution gas and the gas equivalent energy content of conventional oil or bitumen. The determination of WEARR is similar to the previous section 2.5.1, with the difference being the calculation of the average daily production (ADP).

The ADP for solution gas will be based upon the well event total production of both the solution gas and the gas equivalent energy content of conventional oil or bitumen (see section 2.3 for details).

2.5.3 Flow Split Disposition WEARR Calculation

For flow split disposition to multiple ERCB facilities there can be more than one well event average royalty rate calculated based on the ISC dispositions reported at the triggered facilities.

The following is an example to illustrate the determination and calculation of royalty rates for a well event that splits its production between 2 royalty triggering facilities:

The Par Price, as determined and published by the department, is as follows:
Methane ISC PP: $6.66/GJ
Ethane ISC PP: $7.20/GJ

Then r_p % is calculated as follows, using Table 2.2.1.1 Price Component (r_p):

Methane:	$r_{p\ methane}\%$	= 9.72%
Ethane:	$r_{p\ ethane}\%$	= 11.85%

For a well event that reports the following:

Raw gas production:	604.50 10^3m^3 for the month
Total heat content	17, 552.39 GJ for the month
Hours on production:	744 hours for the month
MD of the well event:	1,929 metres
CO_2 content:	1.00%
H_2S content:	0.05%

Calculation of quantity component rate:
The well event information in this example is the same as presented in the previous example in Section 2.5.1, where we calculated the quantity components for both methane and ethane to have the same maximum allowable amount of 30%. Also based on this example it was determined that the royalty rates were as follows:

Methane ISC:	39.72%
Ethane ISC:	41.85%
Propane ISC:	30%
Butanes ISC:	30%
Pentanes Plus ISC:	40%

The well event in this example sends its volumes to the following gas plants:

Table 2.5.3.1 - AB GP 0001000 In-stream Components (ISCs)

Product ISC (1)	Volume (10^3m^3) (2)	Heat (GJ) (3)	FCP (4) = (3)/(sum of all ISCs)
C1-IC	442.67473	18,149.66	80.5519 %[A]
C2-IC	64.491912	2,644.17	11.7354 %
C3-IC	29.25418	1,199.42	5.3233 %
C4-IC	9.9099829	406.3093	1.8033 %
C5-IC	3.2211561	132.0674	0.5861 %
Total	549.55196	22,531.63	100 %

Note:
A. *80.5519% = 18,149.66 /22,531.63 * 100*
B. *Decimals are rounded for display purposes in all calculations.*

Table 2.5.3.2 - AB GP 0001001 In-stream Components (ISCs)

Product ISC (1)	Volume (10^3m^3) (2)	Heat (GJ) (3)	FCP (4) = (3)/(sum of all ISCs)
C1-IC	35,897.172	14,717.840	89.0450 %[A]
C2-IC	2,815.7965	1,154.477	6.9847 %
C3-IC	1,005.8017	412.3787	2.4949 %
C4-IC	407.78468	167.1917	1.0115 %
C5-IC	186.96876	76.65719	0.4638 %
Total	403.13524	16,528.540	100%

Note:
*A. 89.04650% = 14,717.840 / 16,528.540 * 100*
B. Decimals are rounded for display purposes in all calculations.

The well event in this example sends its volumes to both Gas Plant 0001000 and Gas Plant 0001001. The total heat content production for this well event is 17,552.39 GJ for the month and of this amount, 76.7% (13,462.68313 GJ) is processed at Gas Plant 0001000 and 23.3% (4,089.70687 GJ) is processed at Gas Plant 0001001.

Table 2.5.3.3 - Well Event FCP Calculated ISCs for AB GP 0001000

Product (1)	Total Well Event Heat (2)	Calculated Facility FCP *(column (4) Table2.5.3.1)* (3)	Well Event (GJ) *= (2) * (3)* (4)
C1-IC	13,462.68313	80.5519 %	10,844.4494
C2-IC	13,462.68313	11.7354 %	1,579.8944
C3-IC	13,462.68313	5.3233 %	716.6559
C4-IC	13,462.68313	1.8033 %	242.7704
C5-IC	13,462.68313	0.5861 %	78.9105
Total		100 %	13,462.68313

Table 2.5.3.4 - Well Event FCP Calculated ISCs for AB GP 0001001

Product (1)	Total Well Event Heat (2)	Calculated Facility FCP *(column (4) Table2.5.3.2)* (3)	Well Event (GJ) *= (2) * (3)* (4)
C1-IC	4,089.70687	89.0450 %	3,641.6799
C2-IC	4,089.70687	6.9847 %	285.6558
C3-IC	4,089.70687	2.4949 %	102.0361
C4-IC	4,089.70687	1.0115 %	41.3687
C5-IC	4,089.70687	0.4638 %	18.9675
Total		100%	4,089.70687

Note:
The Well Event FCP for each Gas Plant will be determined by the Meter Station (MS) identified as the From/To facility.

The WEARR is calculated based on the following table:

Table 2.5.3.5 - WEARR Calculation for Well Event Reporting at AB GP 0001000

Product (1)	**Heat content (GJ)** *(column (4) Table2.5.3.3)* **(2)**	**ISC Calculated Royalty Rate (3)**	**Royalty Heat (GJ)** *= (2) * (3)* **(4)**
C1-IC	10,844.4494	39.72 %	4,307.4153
C2-IC	1,579.8944	41.85 %	661.1858
C3-IC	716.6559	30 %	214.9968
C4-IC	242.7704	30 %	72.8311
C5-IC	78.9105	40 %	31.5642
Total	**13,462.68313 GJ (6)**		**5,287.9932 GJ (5)**

WEARR = Royalty heat (GJ) for the well event / Total heat content (GJ) of the well
= (5) / (6)
= 5,287.9932 / 13,462.68313 * 100
= 39.2789%

The WEARR of 39.2789% is applied to the total heat content of the well to determine the Crown heat.

Table 2.5.3.6 - WEARR Calculation for Well Event Reporting at AB GP 0001001

Product (1)	**Heat content (GJ)** *(column (4) Table2.5.3.4)* **(2)**	**ISC Calculated Royalty Rate (3)**	**Royalty Heat (GJ)** *= (2) * (3)* **(4)**
C1-IC	3,641.6799	39.72 %	1,446.4752
C2-IC	285.6558	41.85 %	119.5469
C3-IC	102.0361	30 %	30.6108
C4-IC	41.3687	30 %	12.4106
C5-IC	18.9675	40 %	7.5870
Total	**4,089.70687 GJ (6)**		**1,616.6306 GJ (5)**

WEARR = Royalty heat (GJ) for the well event / Total heat content (GJ) of the well
= (5) / (6)
= 1,616.6306 / 4,089.70687* 100
= 39.5293 %

The WEARR of 39.5293 % is applied to the total heat content of the well to determine the Crown heat.

2.5.4 Production Entities: Units, Well Groups and Injection Schemes

For production entities such as units, well groups and injection schemes, a weighted average royalty rate is calculated for each well event within the entity based on the facility component proportion (FCP) and rolled-up to determine a weighted aggregate royalty rate of the production entity. Where PE is involved a proportion to the reporting facility is first determined. The calculated heat at the reporting facility must balance to the individual well event ties heat contribution. The proration of the well events contribution to the PE will be based on the well event production data.

The following is an example to illustrate the determination and calculation of royalty rates for a Unit. In this example, there are 5 well events and a unit that deliver natural gas to Gas Plant (GP) 0001234. The GP reports the following in-stream components:

Table 2.5.4.1 - GP 0001234 In-stream Components (ISCs)

Product (1)	Volume (10^3m^3) (2)	Heat (GJ) (3)	FCP (4) = (3)/(sum of all ISCs)
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%

Note:
A. *81.5798% = 88,161.652 / 108,068.000 * 100*

The GP allocates the volumes (column 2) and heats (column 3), from the above table to each of the well events and units tied to it, as per the following table:

Table 2.5.4.2 - Reported Streams break-down of Volume and Heat to AB GP 0001234

Stream (1)	Volume (10^3m^3) (2)	Heat (GJ) (3)	% Contribution of Reporting Facility Heat (4)
Well Event 1	429.220	17,550.396	16.2401% [A]
Well Event 2	69.937	2,898.382	2.6820%
Well Event 3	161.895	6,648.342	6.1520%
Well Event 4	395.909	16,190.750	14.9820%
Well Event 5	514.406	21,008.230	19.4398%
Unit 1	1,072.233	43,771.900	40.5040%
Total	2,643.600	108,068.000	100.00%

Note:
A. *16.2401% = 17,550.396 / 108,068.000 * 100*

Based on the heat allocation to Unit 1 of 43,771.900 GJ from the above table, and the in-stream component FCP from Table 2.5.4.1, the ISC allocation for the unit can be determined as follows:

Table 2.5.4.3 - Unit 1 Break-down of ISC Heat to AB GP 0001234

Product (1)	**Total Well Event Heat (2)**	**Calculated Facility FCP** *(From Table 2.5.4.1 column 4)* **(3)**	**Well Event (GJ)** *= (2) * (3)* **(4)**
C1-IC	43,771.9	81.5798%	35,709.03
C2-IC	43,771.9	11.3606%	4,972.75
C3-IC	43,771.9	5.0110%	2,193.41
C4-IC	43,771.9	1.6419%	718.69
C5-IC	43,771.9	0.4067%	178.02
Total		100%	43,771.90

The next step is to calculate the estimated heat for each of the ISCs for each of the well events within the unit. To determine the raw gas heat amount for each of the well events based on the raw gas volume reported, we determine the proration as per the following table:

Table 2.5.4.4 - Calculation of Heat for Well Events within Unit 1

Well Event Tie	**Reported Raw Gas Production (10^3 m^3) (1)**	**%Contribution to Unit (2) = (1)/(4)**	**Heat (GJ) (3) = (2)*(5)**
Well Event A	324.53	27.9770%[A]	12,246.0493[B]
Well Event B	74.89	6.4561%	2,825.9533
Well Event C	131.48	11.3346%	4,961.3612
Well Event D	336.18	28.9813%	12,685.6588
Well Event E	292.91	25.2511%	11,052.8774
Total	1,159.99 **(4)**	100%	43,771.90 **(5)**

Note:
*A. 27.9770% = (1)/(4) = 324.53 / 1,159.99 * 100*
*B. 12,246.0493 = (2) * (5) = 27.9770% * 43,771.90*

Next, using the heat derived in the above table and the FCP from Table 2.5.4.1, the ISC heat is determined for each of the well events within the unit, as follows:

Table 2.5.4.5 - Unit 1's Well Event Heat

Product	FCP (1) *(From Table 2.5.4.1)*	Well Event (GJ) A (2)=(1)*(7)	B (3) =(1)*(8)	C (4) =(1)*(9)	D (5)=(1)*(10)	E (6) =(1)*(11)	Total *(Sum A to E)* *(12)*
C1-IC	81.58%	9,990.30[A]	2,305.40	4,047.47	10,348.94	9,016.92	35,709.03
C2-IC	11.36%	1,391.22	321.05	563.64	1,441.17	1,255.67	4,972.75
C3-IC	5.01%	613.65	141.61	248.61	635.68	553.86	2,193.41
C4-IC	1.64%	201.07	46.40	81.46	208.29	181.48	718.70
C5-IC	0.41%	49.80	11.49	20.18	51.59	44.95	178.01
Total	100%	12,246.04 (7)	2,825.95 (8)	4,961.36 (9)	12,685.67 (10)	11,052.88 (11)	43,771.90

Note:
*A. 9,990.30 = 81.58% * 12,246.05*

The Par Price, as determined and published by the department, and relevant information reported by the operator of each well event, within the unit, are as follows:

Table 2.5.4.6 - Well Event Data

	Well Events				
Input for Unit 1	**A**	**B**	**C**	**D**	**E**
C1 Par Price	\$6.66	\$6.66	\$6.66	\$6.66	\$6.66
C2 Par Price	\$7.20	\$7.20	\$7.20	\$7.20	\$7.20
CO_2 content	1%	0%	2%	2.95%	0%
H_2S content	0%	2.21%	0%	0%	0%
AGF	1.00	1.00	1.00	1.00	1.00
Raw gas production ($10^3 m^3$ for the month)	324.53	74.89	131.48	336.18	229.91
Hours of production	620	562	744	701	657
ADP (10^3 m^3/day)	12.5625	3.1981	4.2413	11.5097	8.3985
MD (metres)	1,500	2,566	3,152	1,956	1,927
Depth Factor	1.00	1.6461	2.4838	1.00	1.00

Based on the information in the table above, the following table determines each well event's royalty rates for methane and ethane and their respective weighted averages for the unit.

Table 2.5.4.7 - Calculation of Unit 1's Methane and Ethane Royalty Rates

	Well Event					
C1	**A**	**B**	**C**	**D**	**E**	**Total**
(1) r_p	9.72%	9.72%	9.72%	9.72%	9.72%	
(2) r_q	26.5625%	-10.2856%	-11.4620%	25.5097%	17.1956%	
(3) = (1)+(2) R% = r_p%+r_q%	36.2825%	5.0000%	5.0000%	35.2297%	26.9156%	
(4) C1-IC (GJ)	9,990.30	2,305.41	4,047.47	10,348.94	9,016.92	35,709.03**(9)**
(5) = (3)*(4) Royalty Liable GJ	3,624.73	115.2	202.37	3,645.90	2,426.96	10,015.23(**8**)
(6) = (8)/(9) Weighted %						**28.0468%**
C2						
(1) r_p	11.85%	11.85%	11.85%	11.85%	11.85%	
(2) r_q	26.5625%	-10.2856%	-11.4620%	25.5097%	17.1956%	
(3) = (1)+(2) R% = r_p%+r_q%	38.4125%	5.0000%	5.0000%	37.3597%	29.0456%	
(4) C2-IC (GJ)	1,391.22	321.05	563.64	1,441.17	1,255.67	4,972.75**(9)**
(5) = (3)*(4) Royalty Liable GJ	534.40	16.05	28.18	538.42	364.72	1,481.77**(8)**
(6) = (8)/(9) Weighted %						**29.7978%**

Notes:
A. *The r_p is calculated using Table 2.2.1.1*
B. *The r_q is calculated as per Section 2.2.2.2*
C. *As previously noted that the royalty rates for propane (C3), butanes (C4) and pentanes plus (C5+) are fixed at 30%, 30% and 40%.*

The Unit WEARR is the weighted average royalty rate for all the well events where the weightings are based upon the individual heat content of the in-stream components. Calculations are completed based on the following table:

Table 2.5.4.8 - WEARR Calculation for the Unit 1

Product (1)	**Heat content (GJ)** *(column (12) Table2.5.4.5)* **(2)**	**ISC Calculated Royalty Rate (3)**	**Royalty Heat (GJ)** *= (2) * (3)* **(4)**
C1-IC	35,709.03	28.0468%	10,015.24
C2-IC	4,972.75	29.7978%	1,481.77
C3-IC	2,193.41	30 %	658.02
C4-IC	718.69	30 %	215.61
C5-IC	178.02	40 %	71.21
Total	**43,771.90 GJ (6)**		**12,441.85 GJ (5)**

WEARR = Royalty heat (GJ) of the unit / Total heat content (GJ) of the unit
= (5) / (6)
= 12,441.85 / 43,771.90 * 100
= 28.4243%

The WEARR of 28.4243% is applied to the total heat content of the unit to determine the Crown heat.

2.5.5 Raw Gas

The well event average royalty rate (WEARR) for raw gas allocation (RGA) is calculated based on the ISC factors on the RGA submission in the Petroleum Registry (PRA) reported by the seller. For natural gas that is sold in its raw (unprocessed) state, the point of determination for royalties continues to be at the point of sale.

In situations where ISCs are not reported such as royalty liable lease fuel activity reporting purchase receipt (PURREC), methane and ethane royalty rates will apply to gas and ethane respectively.

2.6 Prices

Facility Average Price (FAP):
The valuation price for gas is a facility average of the individual ISC product reference prices, weighted by the ISC composition, subject to a gas transportation adjustment for each ERCB facility. For the purpose of determining FAP, an ERCB facility is either a Gas Plant or Gathering System.

The determination, calculation, and use of FAP will not change under the NRF.

Reference and Par Prices:
Under the NRF, the par and reference prices will continue to be determined as they are under the current royalty regime by the department. All reference prices will continue to be the same as the existing royalty system as follows:

- The monthly reference price for methane ISC will continue to be determined by the department
- The monthly reference price for ethane, propane, butanes and pentane plus, whether extracted or left in the gas stream would continue to be determined by the department.

Corporate Average Price: (CAP)
Under the current royalty regime a new royalty client has the option of choosing either the Reference Price or the CAP valuation method. A royalty client's CAP is based upon its total gas sales value divided by its total gas sales volume, subject to a minimum of 90% of the gas reference price.

The CAP will be terminated effective January 2009, after which all royalty clients will pay royalties based on the gas reference price.

2.7 Royalty Valuation

The value charged to royalty clients, as a gross amount, is as follows:

- Natural gas (including methane ISC, ethane ISC, propane ISC, butanes ISC and pentanes plus ISC)
  Royalty Valuation = Crown heat × WEARR × FAP,
  Where:
  Crown heat = Client heat × Crown Interest.
- Extracted ethane, propane, butanes and pentanes plus
  Royalty Valuation = Crown heat × calculated royalty rate × reference prices
- Solution gas
  Royalty Valuation = Crown heat × WEARR × FAP
- Raw gas sale
  Royalty Valuation = Crown heat × RGAWEARR × 80% of gas reference price
- Field condensate
  Royalty Valuation = Crown royalty volume × pentanes plus reference price

For example let's assume the following:

- Crown Heat = 351.0 GJ
- WEARR = 39.038%
- FAP = $6.66

Royalty Valuation = Crown Heat * WEARR * FAP
= 351.0 GJ * 39.038% * $6.66
= $912.58

Transportation and fractionation adjustments are included in the FAP calculation.

2.8 Royalty Programs

Otherwise Flared Solution Gas: (OFSG)

The department will retain the OFSG program and effective January 2009 production month the program would be extended to include bitumen wells.

Tiers

Under the new royalty framework there will no longer be vintages assigned to natural gas i.e. natural gas will no longer be classified as "old" or "new".

SECTION 3 - NATURAL GAS DEEP DRILLING PROGRAM

3.1 Overview

The Natural Gas Deep Drilling Program (NGDDP) will be available, starting January 2009 production month, as a royalty adjustment for natural gas wells with production at true vertical depths (TVD) greater than 2,500 metres.

3.2 Eligibility

The NGDDP is a well-based program; as such the eligibility requirements will be determined at the well level.

3.2.1 Eligible Wells

In order to be eligible to receive a royalty adjustment the well must meet the following conditions:

- The well must be considered a natural gas well; this program does not apply to conventional oil, oilsands or bitumen wells. To be designated by the department as a natural gas well it must have a gas-oil ratio is greater than 1,800 m^3:1 m^3,
- A Crown interest greater than 0%,
- Commenced spudding or deepening on or after October 25, 2007, where deepening means drilling below the existing TVD, and
- Drilled into a producing zone with a TVD in excess of 2,500 metres, where TVD is the vertical distance, in metres, measured in a perpendicular line from the kelly bushing of a well to the top of the zone that the well is producing natural gas in paying quantities.

3.2.2 Non Eligible Wells

A well is considered non eligible for NGDDP if any one of the following occurs:

- A well cannot qualify for both the natural gas and conventional oil deep drilling programs.
- A well with 100% freehold interest would not be eligible to receive any NGDDP royalty adjustment.
- It was completed within a drilling spacing unit that previously received a royalty exemption or adjustments under prior regulations.
- If a well event in a well received benefits under any previous program then the well containing that well event may not be eligible for the NGDDP.
- A natural gas well that was previously abandoned.
- If according to the records of the ERCB either of the following occurs:
  - It is considered to be an off target well, or
  - A well within the pool boundaries designated by the ERCB as at June 1, 1985.

3.3 Calculation of the Royalty Adjustment

Once a well is determined to be eligible to receive the NGDDP, the determination of the actual royalty adjustment will be based upon the measured depth (MD).

The MD of a well is the longest distance in metres, according to the records of the ERCB, measured along the bore of the well from the kelly bushing of the well to the base of the deepest natural gas producing interval. It is important to note that the MD used to calculate the NGDDP differs from the MD used for the purpose of calculating the depth factor (DF) in the royalty equation. For the NGDDP, there is only one MD for each well and it is to the base of the deepest/longest producing interval. Whereas, the MD used to calculate the DF is determined for each producing well event within a well, and is the distance to the bottom of the gross completion interval (GCI), according to the records of the ERCB. If a well has a number of drains contributing to the production of one producing well event, within a well, then the MD is the sum of the drain's total depth and the MD (the GCI bottom) of the producing event (with no double counting), according to the records of the ERCB.

The NGDDP royalty adjustment will depend on the classification of the well. Royalty adjustments beyond 4,000 metres differ depending on whether the well in question is an exploratory or development well. Exploratory wells with depths greater than 4,000 metres receive an additional 25% adjustment.

Classification of wells will be determined by the ERCB. An exploratory well is a well drilled with a designation as a New Field Wildcat (NFW), New Pool Wildcat (NPW), or Deeper Pool Test (DPT) according to the records of the ERCB. A development well is a well drilled with a designation as a development well or an outpost well according to the records of the ERCB.

The royalty adjustments for these classifications are specified in the following sections (3.3.1 & 3.3.2).

3.3.1 Royalty Adjustment for Development Wells

The total royalty adjustment for an eligible well classified as a development well is determined in accordance with the following formula:

Total royalty adjustment = A+B+C+D+E

Where:

- A is the number of metres greater than 2,500 but not more than 3,500 multiplied by $625/metre
- B is the number of metres greater than 3,500 but less than 4,000 multiplied by $2,500/metre
- C is the number of metres greater than 4,000 but less than 5,000 multiplied by $2,500/ metre
- D is the number of metres greater than 5,000 multiplied by $3,000/metre
- E is the supplemental royalty adjustment determined as follows:
  - if the measured depth is less than 4,000 metres, then E is $0
  - if the measured depth is 4,000 metres or more, then E is $875,000

The maximum royalty adjustment is $8,000,000 for development wells.

Table 3.3.1.1 - Development Well Royalty Adjustment per metre

MD	Benefit per metre drilled in the depth range ($/m)				Supplemental Adjustment
	2,500 < MD ≤ 3,500	3,500 < MD ≤ 4,000	4,000 < MD ≤ 5,000	MD > 5,000	
2,500	$625				
3,000	$625				
3,500	$625	$2,500			
4,000	$625	$2,500	$2,500		$875,000
4,500	$625	$2,500	$2,500		$875,000
5,000	$625	$2,500	$2,500	$3,000	$875,000
5,000+	$625	$2,500	$2,500	$3,000	$875,000

3.3.2 Royalty Adjustment for Exploratory Wells

The total royalty adjustment for an eligible well classified as an exploratory well is determined in accordance with the following formula:

Total royalty adjustment = A+B+C+D+E
Where:

- A is the number of metres greater than 2,500 but not more than 3,500 multiplied by $625/metre
- B is the number of metres greater than 3,500 but less than 4,000 multiplied by $2,500/metre
- C is the number of metres greater than 4,000 but less than 5,000 multiplied by $3,125/ metre
- D is the number of metres greater than 5,000 multiplied by $3,750/metre
- E is the supplemental royalty adjustment determined as follows:
  - if the measured depth is less than 4,000 metres, then E is $0
  - if the measured depth is 4,000 metres or more, then E is $875,000

The maximum royalty adjustment is $10,000,000 for exploratory wells.

Table 3.3.2.1 - Exploratory Well Royalty Adjustment per metre

MD	**Benefit per metre drilled in the depth range ($/m)**				**Supplemental Adjustment**
	2,500 < MD ≤ 3,500	**3,500 < MD ≤ 4,000**	**4,000 < MD ≤ 5,000**	**MD > 5,000**	
2,500	$625				
3,000	$625				
3,500	$625	$2,500			
4,000	$625	$2,500	$3,125		$875,000
4,500	$625	$2,500	$3,125		$875,000
5,000	$625	$2,500	$3,125	$3,750	$875,000
5,000+	$625	$2,500	$3,125	$3,750	$875,000

3.4 Lengthening/Deepening - Eligibility and Calculation of Incremental Adjustments

A NGDDP well may be eligible for additional royalty adjustments under the NGDDP if it is lengthened, that is there is an increase in the wells MD with no increase to its TVD, or the well is deepened, that is there is increase in both TVD and MD.

3.4.1 Lengthening

A well that has already qualified for and is receiving a NGDDP royalty adjustment may be eligible to receive incremental adjustments if its MD is increased with no change in its TVD. This incremental adjustment will be based upon the new longer MD of the lengthened segment of the well.

The incremental adjustment will only be applied if the current five years benefit term has not expired, i.e. the well is still within five years of its Finished Drilled Date (FDD). The allowable adjustment will be the difference between the new adjustment and the actual NGDDP adjustment provided to the royalty client. Any unused adjustment after the original five year term date will be lost. If the current five year adjustment term has expired, i.e. the well is in the 6th year after the FDD then no incremental royalty adjustment will be granted.

For example, a well that has qualified for the NGDDP with a FDD in May 2009 and with a MD of 3,255 metres begins receiving royalty adjustments the next month. The following year this well is lengthened to a MD of 3,500 metres, and there is no change to the TVD. The well receives the additional royalty adjustment equal to the incremental 245 metres of MD i.e. the difference between 3,500 and 3,255 metres. The well's FDD does not change, it has 5 years to receive this adjustment from the original FDD of May 2009 (detailed examples are provided at the end of this section).

3.4.2 Deepening

A well that has already qualified for and is receiving a NGDDP royalty adjustment may be eligible to receive incremental adjustments if both its TVD and MD have increased beyond their previous lengths. This incremental adjustment will be based upon the new longer MD and the five year term to receive this additional adjustment may be restarted to the FDD of the deepened segment, dependant on the following:

- If the current five year term has not expired, i.e. the well is still within 5 years of its FDD, a new adjustment will be calculated and it is the difference between the new adjustment at the new deeper MD and the previous actual adjustment balance received by the royalty client. A new five year term will be established based on the new FDD. Any unused adjustment after the new five year term will be lost.

- If the current five year adjustment term has expired, i.e. the well is in the 6th year after the FDD, a new adjustment amount will be calculated based on the new MD. The adjustment will be the difference between the new adjustment, at the deeper MD, and the previous actual adjustment balance received by the royalty client. A new five year term will be established based on the new FDD. Any unused adjustment after the new five year term will be lost.

For example, a well qualifies for the NGDDP with a FDD in June 2009, has a TVD of 3,200 metres, a MD of 4,200 metres and begins receiving royalty adjustments the next month. The following year the well is deepened to a new TVD of 4,725 metres and with a new MD of 5,500 metres, and this new drilling has a FDD in September 2010. The well receives the additional royalty adjustment equal to the incremental 1,300 metres of MD (i.e. the difference between 5,500 and 4,200 metres) and now has 5 years to receive this adjustment from the new FDD of September 2010 (detailed examples are provided at the end of this section).

3.5 Implementation and Transition

The NGDDP is a well-based program; as such the eligibility requirements will be applied at the well level. Allowable royalty adjustments applicable to a well will be distributed to all well events of that well. The distribution of benefits will be based on gas production from each well event relative to the total production from all well events.

NGDDP royalty adjustments may not reduce the royalty rate of a qualified well below the minimum of 5% pre-gas cost allowance for the in-stream components (i.e. natural gas), whereas condensate may be allowed a minimum of 0%.

Wells that are eligible for the NGDDP will have a maximum of 5 years following the FDD to receive the royalty adjustment. The FDD is the date at which the total depth of a well is reached, that is, the date when drilling is completed. For example, if a well has a FDD of January 1, 2009, the well has until December 31, 2013, to receive the royalty adjustment.

There will be a transition phase to accommodate wells that currently receive or will be eligible to receive benefits under either the DGRHP or the RAP prior to implementation of the NGDDP. Wells spudded on or after October 25, 2007, and with production prior to December 31, 2008, are eligible to receive DGRHP or RAP royalty adjustments. However, the DGRHP or RAP adjustments received up to December 2008 production period, will be deducted from the eligible NGDDP adjustments after that date.

For example, if a well is drilled on or after October 25, 2007, and it has been determined to be eligible to receive a DGRHP adjustment of $1.2 million, and during production year 2008 this well has actually received $500,000, when the well is transitioned into the NGDDP program the balance is carried forward and deducted from the NGDDP eligible amount. If that well qualifies for the NGDDP with an estimated royalty adjustment of $3 million, then the well will receive the remaining adjustment of $2.5 million over the five year period, the original $3 million less the $500,000 received.

Wells that currently receive DGRHP or RAP and do not qualify for the NGDDP, i.e. they have a spud date before October 25, 2007, and then these wells will have their benefits ceased as of December 2008 production period.

For wells that are deepened on or after October 25, 2007, the eligibility will be for the incremental drilled depth below the existing TVD.

3.6 Termination of the NGDDP

The length of the NGDDP program has been predetermined to be 5 years. Wells with a spud date after December 31, 2013, will not qualify for this program. All royalty adjustments will terminate within 5 years of the well's FDD or December 31, 2018, whichever occurs first, whether the full benefits have been realized or not. There will be no royalty adjustments granted under this program after December 31, 2018.

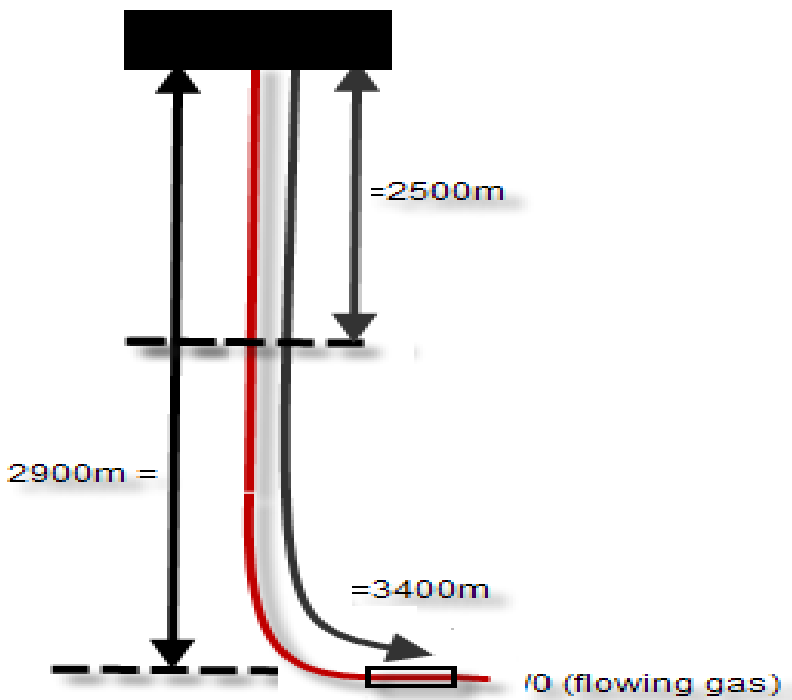
3.7 NGDDP Examples

The following are examples to illustrate the calculation of the NGDDP royalty adjustment:

Example 1:

A development well is drilled with a TVD of 2,900 metres and a MD of 3,400 metres, as shown in the diagram below.

This well qualifies for the NGDDP since its TVD is greater than 2,500 metres.



Calculation of the NGDDP adjustment:

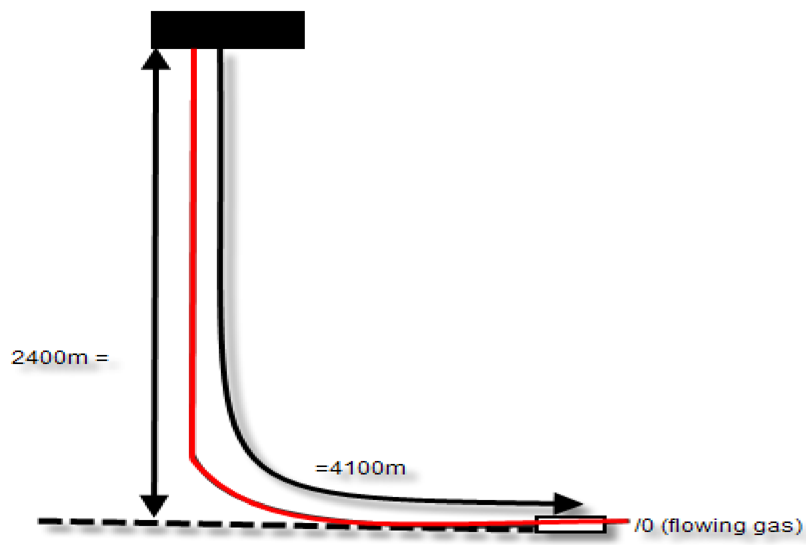
Since the MD for this well is 3,400 metres it falls within the 2,500 < Depth ≤ 3,500 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

= (3,400m – 2,500m) * $625.00/m

= (900m) * $625.00/m

= $ 562,500.00

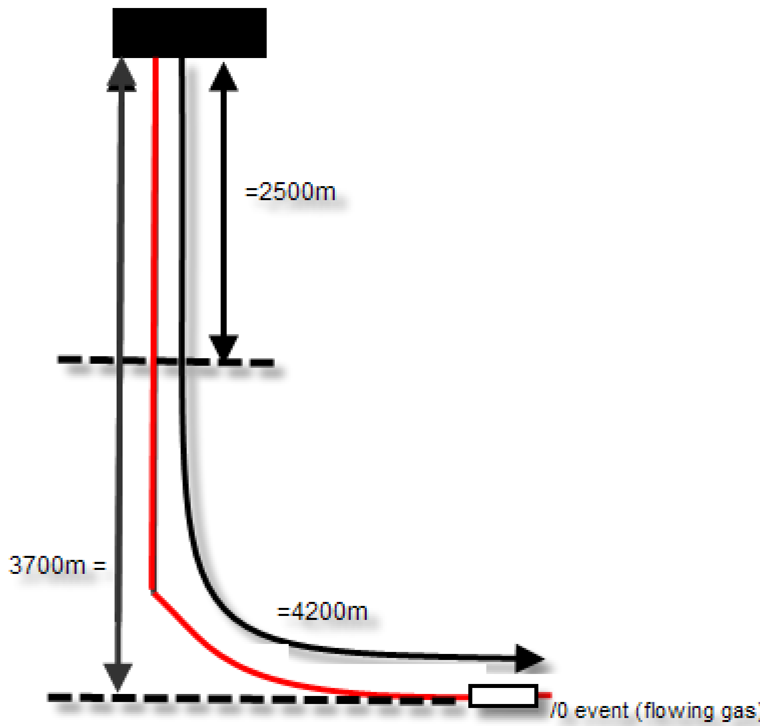
Example 2:
A development well is drilled with a TVD of 2,400 metres and a MD of 4,100 metres, as shown in the diagram below.



This well does not qualify as it does not have a TVD greater than 2,500 metres

Example 3:
A development well is drilled with a TVD of 3,700 metres and a MD of 4,200 metres, as shown in the diagram below.

This well qualifies for the NGDDP since its TVD is greater than 2,500 metres.



The calculation of the NGDDP adjustment is as follows:

A. For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.1.1 (development wells) the royalty adjustment is:
= (3,500m – 2,500m) * $625.00/m
= 1,000m * $625.00/m
= $ 625,000.00

B. For the MD between 3,500 < Depth ≤ 4,000 range of Table 3.3.1.1 (development wells) the royalty adjustment is:
= (4,000m – 3,500m) * $2,500.00/m
= 500m * $2,500.00/m
= $ 1,250,000.00

C. For the MD between 4,000 < Depth ≤ 5,000 range of Table 3.3.1.1 (development wells) the royalty adjustment is:
= (4,200m – 4,000m) * $2,500.00/m
= 200m * $2,500.00/m
= $ 500,000.00

D. Since this well has a MD greater than 4,000 metres it is entitled to the supplemental adjustment of $875,000.00

The total royalty adjustment for this well is the sum of the calculated adjustments from parts A to D, above:

= A + B + C + D

= $625,000 + $1,250,000 + $500,000 + $875,000

= $3,250,000.00

The total NGDDP royalty adjustment for this well is $3,250,000.

Example 4:

An exploratory well is drilled with a TVD of 3,700 metres and a MD of 4,200 metres (see example 3 for diagram of this well since it is the exact same well except that now it is an exploratory well whereas example 3 was a development well).

This well qualifies for the NGDDP since its TVD is greater than 2,500 metres.

The calculation of the NGDDP adjustment is as follows:

A. For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.2.1 (exploratory wells) the royalty adjustment is:

= (3,500m – 2,500m) * $625.00/m

= 1,000m * $625.00/m

= $ 625,000.00

B. For the MD between 3,500 < Depth ≤ 4,000 range of Table 3.3.2.1 (exploratory wells) the royalty adjustment is:

= (4,000m – 3,500m) * $2,500.00/m

= 500m * $2,500.00/m

= $ 1,250,000.00

C. For the MD between 4,000 < Depth ≤ 5,000 range of Table 3.3.2.1 (exploratory wells) the royalty adjustment is:

= (4,200m – 4,000m) * $3,125.00/m

= 200m * $3,125.00/m

= $ 625,000.00

D. Since this well has a MD greater than 4,000 metres it is entitled to the supplemental adjustment of $875,000.00

The total royalty adjustment for this well is the sum of the calculated adjustments from parts A to D, above:

= A + B + C + D

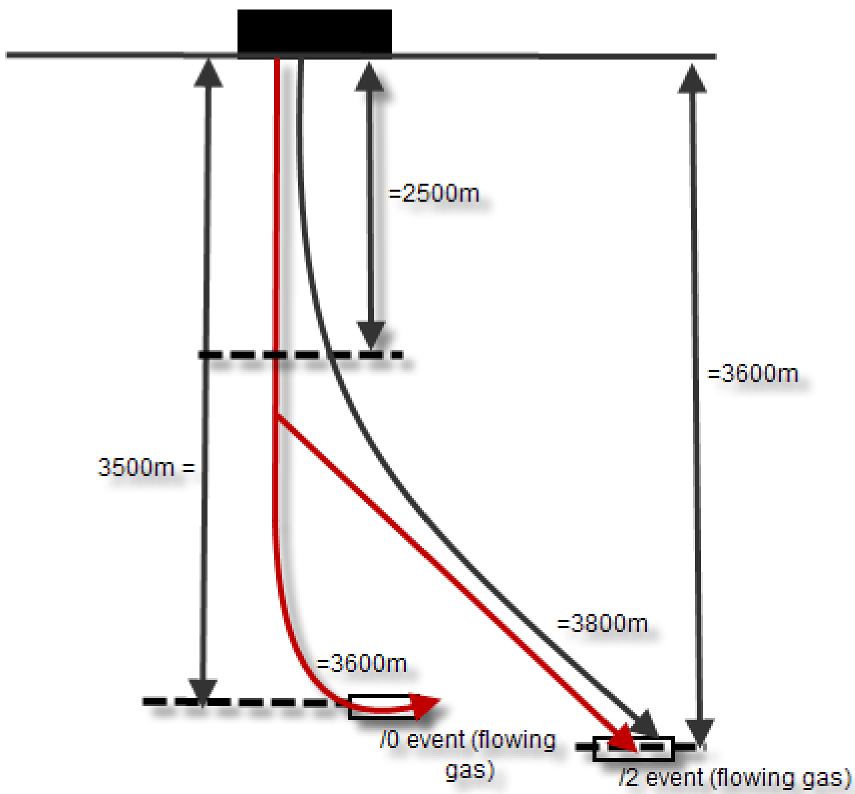
= $625,000 + $1,250,000 + $625,000 + $875,000 = $3,375,000.00

The total NGDDP royalty adjustment for this well is $3,375,000.

Example 5:
An exploratory well is drilled with 2 well events each reporting flowing gas production. Each well event has the following depths (as shown in the diagram below):

Well event /0		Well event /2	
TVD	= 3,500m	TVD	= 3,600m
MD	= 3,600m	MD	= 3,800m

This well qualifies for the NGDDP since its TVD is greater than 2,500 metres.



The calculation of the NGDDP adjustment amount is based on the longest MD, as follows:

A. For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.2.1 (exploratory wells) the royalty adjustment is:

= (3,500m – 2,500m) * $625.00/m
= 1,000m * $625.00/m
= $ 625,000.00

B. For the MD between 3,500 < Depth ≤ 4,000 range of Table 3.3.2.1 (exploratory wells) the royalty adjustment is:

= (3,800m – 3,500m) * $2,500.00/m

= 300m * $2,500.00/m
= $ 750,000.00

The total royalty adjustment for this well is the sum of the calculated adjustments from parts A and B, above:

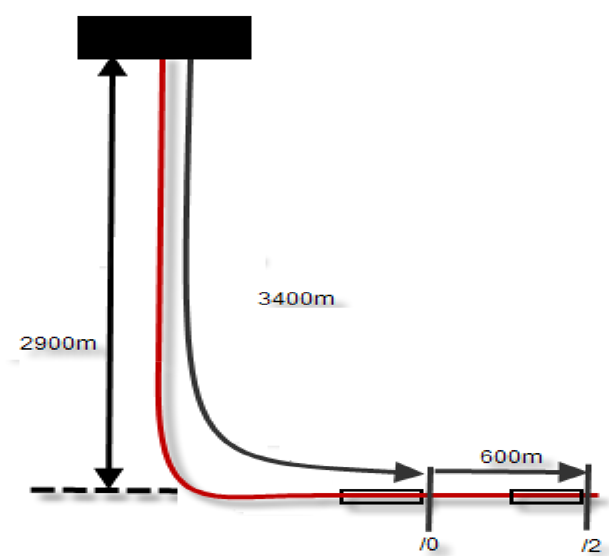
= A + B
= $625,000 + $750,000
= $1,375,000.00

The total NGDDP royalty adjustment for this well is $1,375,000 and will adjust the royalties of both well events until the total adjustment has been applied.

Example 6:

A development well is drilled as follows:

- This well is drilled to a MD of 4,000 metres with a TVD of 2,900 metres, as shown in the diagram below. This well has a FDD of January 2009.
- The /0 event, with TVD of 2,900 metres and a MD of 3,400 metres, is brought on production in January 2009. At this time, there is no production down hole of this well event.
- The /2 event, down hole of the /0 event has a TVD of 2,900 metres and a MD of 4,000 metres. This well event is brought on production in February 2010.



The NGDDP adjustment is for this well occurs as follows:

1. As of January 2009 - at this time only the /0 event is on production, thus the NGDDP adjustment is based on a MD of 3,400 metres. The NGDDP Regulation states that the longest producing interval determines the adjustment even thought this well has been drilled to a MD of 4,000 metres the adjustment, at this time, is based only on the MD of 3,400 metres. Determination of the adjustment is as follows:

   For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

   = (3,400m – 2,500m) * $625.00/m
   = 900m * $625.00/m
   = $ 562,500.00

   The total NGDDP royalty adjustment for this well is $ 562,500.00 starting January 2009 and will continue for 5 years until December 2013.

2. As of February 2010 - at this time the /2 event is brought on production for the portion of the well that was previously drilled to a MD of 4,000 metres. The NGDDP adjustment will be increased based on the incremental MD of 600 metres, as per the following steps:

   A. Calculate the adjustment to the MD of 4,000 metres:

      (i) For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

      = (3,500m – 2,500m) * $625.00/m
      = 1,000m * $625.00/m
      = $ 625,000.00

      (ii) For the MD between 3,500 < Depth ≤ 4,000 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

      = (4,000m – 3,500m) * $2,500.00/m
      = 500m * $2,500.00/m
      = $ 1,250,000.00

      (iii) Since this well has a measured depth of 4,000 metres it is entitled to the supplemental adjustment of $875,000.00

      The total NGDDP adjustment to 4,000 metres is:

      = (i) + (ii) + (iii)
      = $625,000 + $1,250,000 + $875,000.00
      = $2,750,000.00

B. Determination of actual adjustment given:
   Part of the $562,500.00 from Part 1, above, was given to the royalty client – for this example let us assume that $475,000.00 in royalty adjustment was a NGDDP benefit.

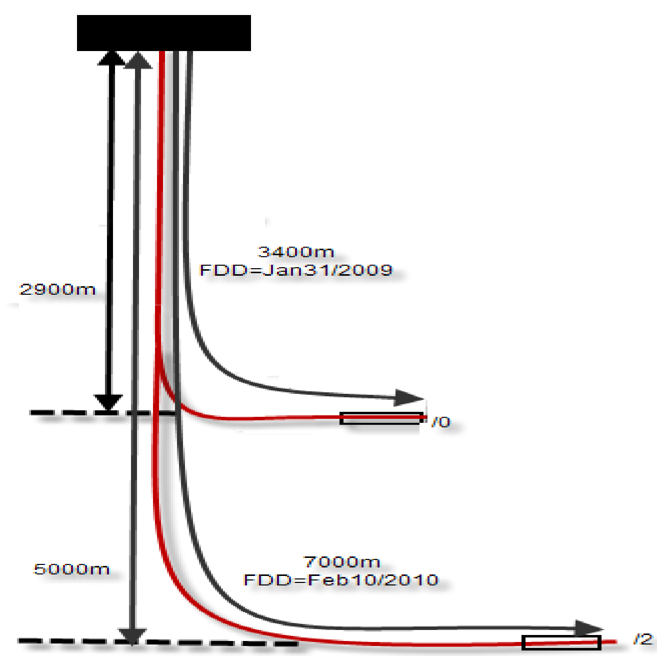
C. Determination of NGDDP adjustment as of February 2010 is:
   = [latest/longest adjustment, Part 2.A.] less [actual adjustment given, Part 2.B.]
   = $2,750,000.00 - $475,000.00
   = $2,275,000.00

Effective February 2010 the NGDDP adjustment is $2,275,000.00, however because this is a lengthening and not a deepening the termination date of the well does not change, that is, the December 2013 date by which the adjustment must be received does not change.

Example 7:
A development well is drilled as follows:

- Initial drilling: The /0 event: has a TVD of 2,900 metres, a MD of 3,400 metres, and a FDD of January 2009; from this date forward there is production.

- The /2 event is drilled at a later date and with a FDD of February 2010. This well event has a TVD of 5,000 metres and a MD of 7,000 metres.



The NGDDP adjustment for this well occurs as follows:

1. As of January 2009 - at this time only the /0 event has been drilled and is on production, thus the NGDDP adjustment is based on a MD of 3,400 metres. Determination of the adjustment is as follows:

   For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

   = (3,400m – 2,500m) * $625.00/m
   = 900m * $625.00/m
   = $ 562,500.00

   The total NGDDP royalty adjustment for this well is $ 562,500.00 starting January 2009 and will continue for 5 years until December 2013.

2. As of February 2010 - at this time the /2 event is drilled and brought on production. Since the /2 event has a TVD that is greater than the /0 event this is a deepening situation. The NGDDP adjustment will be increased based on the TVD and MD of this well event, as per the following steps:

   A. Calculate the adjustment to the MD of 7,000 metres:

      (i) For the MD between 2,500 < Depth ≤ 3,500 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

      = (3,500m – 2,500m) * $625.00/m
      = 1,000m * $625.00/m
      = $ 625,000.00

      (ii) For the MD between 3,500 < Depth ≤ 4,000 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

      = (4,000m – 3,500m) * $2,500.00/m
      = 500m * $2,500.00/m
      = $ 1,250,000.00

      (iii) Since this well has a measured depth greater than 4,000 metres it is entitled to the supplemental adjustment of $875,000.00

      (iv) For the MD between 4,000 < Depth ≤ 5,000 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

      = (5,000m – 4,000m) * $2,500.00/m
      = 1,000m * $2,500.00/m
      = $ 2,500,000.00

      (v) For the MD between Depth > 5,000 range of Table 3.3.1.1 (development wells) the royalty adjustment is:

= (7,000m – 5,000m) * $3,000.00/m
= 2,000m * $3,000.00/m
= $ 6,000,000.00

The total NGDDP adjustment to 7,000 metres is:
= (i) + (ii) + (iii) + (iv) + (v)
= $625,000 + $1,250,000 + $875,000 + $2,500,000 + $6,000,000
= $11,250,000.00

Since this exceeds the maximum NGDDP adjustment for a development well, the adjustment is set to $8,000,000.00.

B. Determination actual adjustment given:
Part of the $562,500.00 from Part 1, above, was given to the royalty client – for this example let us assume that $541,000.00 in royalty adjustment was a NGDDP benefit.

C. Determination of NGDDP adjustment as of February 2010 is:
= [latest/longest adjustment, Part 2.A.] less [actual adjustment given, Part 2.B.]
= $8,000,000.00 - $541,000.00
= $7,459,000.00

Effective February 2010, the NGDDP adjustment is $7,459,000.00, and because this is a deepening situation it restarts the 5 year termination date of the adjustment such that this well will receive the NGDDP starting February 2010 until January 2015.

SECTION 4 - GAS COST ALLOWANCE

4.1 Overview

Under the New Royalty Framework (NRF), the department will implement the following changes to the monthly and annual allowable cost processes effective the production year commencing January 2009:

1. The Unit Operating Cost Rate (UOCR) will no longer be used to determine operating cost deductions for all royalty clients (owners and non-owners). In its place, actual operating costs will be deducted for owners according to the reported costs and ownership allocations identified by each Facility Cost Centre (FCC) operator.

2. The Corporate Effective Royalty Rate (CERR) will be replaced with a Facility Effective Royalty Rate (FERR). The FERR will be used to determine the monthly and annual Crown share of allowable costs, including capital, operating and custom processing cost allowances. The FERR will be applied at the client/facility level. The 2009 production year annual costs will be processed in the April 2010 Initial Annual Billing Period (IABP) invoice.

3. Starting with the 2009 production year's allowable cost reporting, due in early 2010, there will be some changes to the annual reporting forms. Specifically:
   a. The annual AC4 reporting requirements will be combined with the Annual AC2 reporting requirements; operators will be required to file actual operating costs for all FCCs.
   b. The annual AC3 form will be modified to allow reallocations of capital and operating costs to multiple facilities to align volumes with costs.
   c. 'The 'Reported ERCB Facility Code' and 'Effective Date' (Fields 2.9 and 2.10) on the AC1 will be removed. This also applies to prior production years in that changes to these fields are only available for production months earlier than January 2009.

4.2 Facility Effective Royalty Rate (FERR)

The FERR will be used to determine the monthly and annual Crown share of allowable costs, including capital, operating, and custom processing cost allowances for each royalty client at each ERCB facility. The Crown share of the facility costs will be summed up and shown on the invoice as one deduction for each charge type.

The FERR will be calculated for each royalty client at each ERCB facility based on the following formula, for a given year:

$$\text{FERR} = \frac{\text{Crown royalty value for the client at the ERCB facility(\$)}}{\text{Total value for the client at the ERCB facility (\$)}}$$

4.3 NRF allowable cost changes will be implemented in two phases

4.3.1 Phase 1

The following changes under the NRF will be implemented for the Monthly Estimated Costs Process effective January 2009 to March 2010 production periods:

1. Estimated FERR will be calculated as follows:
   - January 2009 to April 2009 billing period invoices:
     The department will use January 2008 to December 2008 actual production period Crown royalty data to calculate the FERR for each royalty client at each ERCB facility. This will be calculated after the December 2008 billing period invoice run.
   - May 2009 to March 2010 billing period invoices:
     The department will use the January 2009 to April 2009 actual production period Crown royalty data to recalculate the FERR for each royalty client at each ERCB facility. This will be calculated after the April 2009 billing period invoice run.
     Note: Effective the April 2010 billing period invoice, the FERR will be updated at IABP.

2. Estimated Capital and Custom Processing Costs will be calculated as follows:
   - January 2009 to March 2009 billing period invoices:
     The department will use the 2007 actual capital and custom processing costs reported on the AC2, AC3, and AC5 forms. This will be calculated after the December 2008 billing period invoice run.
   - April 2009 to March 2010 billing period invoices:
     The department will use the 2008 actual capital and custom processing costs reported on the AC2, AC3, and AC5 forms. This will be calculated during the April 2009 billing period invoice run.

3. Estimated Operating Costs will be calculated as follows:
   - January 2009 to April 2009 billing period invoices:
     - Designated facilities (all types) and non-designated facilities (processing type):
       The department will use the 2007 actual costs filed on the AC4 along with the AC2 distribution percentages to distribute the costs. In the absence of AC2 distribution percentages the operating costs would default to the FCC operator.
     - Non-designated facilities (compressing and gathering types):
       The department will multiply the compressing and gathering portions of the UOCR rate by the client volumes reported for the January 2008 to December 2008 production periods. This amount will then be added to the processing portion determined above. This will be calculated after the December 2008 billing period invoice run.

- May 2009 to March 2010 billing period invoices:
  - Designated facilities (all types) and non-designated facilities (processing type):
    The department will use the 2008 actual costs filed on the AC4 along with the AC2 distribution percentages to distribute the costs. In the absence of AC2 distribution percentages the operating costs would default to the FCC operator.
  - Non-designated facilities (compressing and gathering types):
    The department will multiply the most recent compressing and gathering portions of the UOCR rate by the client volumes reported for the January 2008 to December 2008 production periods. This amount will then be added to the processing portion determined above. This will be calculated after the April 2009 billing period invoice run.
    Note: Effective the April 2010 billing period invoice, the estimated operating costs will be updated at IABP together with capital costs and custom processing fees.

4. A royalty client may request, at any time, a change or amendment to their estimated FERR and go-forward costs. Upon receipt of this written request, the department will review the validity of these changes.

   The following changes under the NRF will be implemented effective January 2009 production month:

1. AC1 Form:
   The AC1 form, 'Facility Cost Centre Setup/Change', will be modified to display an 'As of Date' that will populate one of two versions of the form based on the date of setup/change on the Petroleum Registry of Alberta (PRA). Changes to this form consist of the removal of the fields relating to the 'Reported ERCB Facility Code' and 'Effective Date' (Fields 2.9 and 2.10), as follows:
   - For pre-NRF periods ('As of Date' on or before December 2008 production month), information may be reported in these fields.
   - For post-NRF periods ('As of Date' on or after January 2009 production month), these fields will not appear.
   - For 'Batch AC1' submissions, with an ('As of Date' of January 2009 production month or later), a warning notification will be sent by PRA via email that these fields will be ignored if a user includes information in the 'Reported ERCB Facility Code' and 'Effective Date' sections.

2. Unit Operating Cost Rate (UOCR):
   The UOCR will no longer be used to determine operating cost deductions for all royalty clients (owners and non-owners). Instead, operating costs would only be distributed to the owners identified by the operator on each FCC. The monthly estimated operating cost deduction will appear as a new charge type,

'Monthly OP Deduction', on the invoice rather than as a deduction within the Crown Royalty charge type.

3. Monthly Allowable Cost Restriction (ACR):
   Operating cost deductions will now be included in determining the monthly allowable cost restriction on the invoice. If the monthly Crown share of estimated costs (capital + operating + custom fees) exceeds the monthly Crown royalties, an ACR adjustment will be shown on the invoice. Monthly allowable cost restrictions will still be applied at the corporate level on the invoice, the same as in the pre-NRF system, to ensure that the total allowable cost deductions do not exceed the Crown royalty for the production month.

4. New clients/facilities:
   For a new royalty client or a new ERCB facility, the department will not automatically determine the monthly estimated go-forward FERR and the estimated dollar amounts for capital costs, operating costs, and custom processing fees. A written request with supporting documentation must be submitted by the royalty client in order for the department to calculate these estimated go-forward amounts. Failure to submit a written request for a go-forward estimate will result in the royalty client not receiving its monthly Crown share of costs.

4.3.2 Phase 2:

Phase 2 of the NRF relating to GCA will be implemented starting in April 2010 billing period. *Currently this segment of the NRF relating to GCA implementation is in the planning phase of development, as such, the information provided here is subject to change.*

The following system changes will be implemented for the Annual Actual Costs Process – effective April 2010 Initial Annual Billing Period (IABP), and also the monthly estimated cost process effective April 2010 to March 2011 production periods (and for the subsequent years thereafter).

1. Changes to Forms:
   With the implementation of NRF, there will be a number of changes to the reporting of gas cost allowance information and the following Petroleum Registry of Alberta (PRA) forms:

   A. AC2 Form:
      Under NRF, actual operating costs will be filed by all operators, in addition to actual capital costs. To accomplish this change, a new AC2-V4 form has been created and will be called the 'Capital and Operating Cost Allowance: Production Years 2009 and Onwards'. This new form is a combination of 2 pre-NRF forms: the 'Operating Costs' (AC4) form and the 'Capital Costs Allowance' (AC2) form.

The following new sections will be added:

- Capital costs allocations to multiple delivery facilities for clients with working interest ownership in the FCC.
- Operating costs allocations to multiple delivery facilities for clients with working interest ownership in the FCC.
- Distribution of operating cost allowance allocations to working interest owners.
- Reporting the ‘Custom Processing Adjustment Factor (CPAF)’ for operating costs.

The deadline for submission of this new form is April 30th. The penalty for late submission of the AC2 form is $100.00 per month (after form due date) to a maximum of 6 months.

B. AC3 Form:
Under NRF, a new AC3-V3 form will be created called ‘Capital and Operating Cost Allowance Reallocation: Production Years 2009 and Onwards’. This form will allow reallocation of capital and operating costs to multiple clients and ERCB facilities. This form will allow royalty clients to eliminate cost restrictions due to misaligned volumes; it will be used to align costs to match with royalty trigger volumes. If a royalty client reallocates costs from a source facility to a destination facility that is not within the same royalty network then the department will disallow this reallocation.

The pre-NRF version of this form included a section called ‘Custom Processing Volume Reallocations’ this section will no longer be required under NRF and will not appear on the new form.

The deadline for submission of this form is May 15th and there is no penalty for late submission of this form (no change from pre-NRF).

C. AC5 Form:
Under NRF, a new AC5-V4 form, ‘Custom Processing Fees Paid’, will be created without Part 3 (Custom Processing fees paid by owners in Facility Cost Centre(s) Tied to ERCB Facility). This part was used to identify custom fees with partial ownership, but will no longer be required since the process to recapture operating costs from non-owners will be eliminated.

The deadline for submission of this form is May 15th (no change from pre-NRF). The penalty for late submission of the AC5 form will be $100.00 per month (after form due date) to a maximum of 6 months.

2. Calculation and Application of FERR:
   Starting with the April 2010 IABP, the department will calculate the actual FERR for each client/facility, based on the annual submissions of actual allowable cost forms. The monthly go-forward estimated FERR for each client/facility will also be populated from the actual cost calculations at IABP.

   A royalty client may request, at any time, a change or amendment to their estimated FERR and go-forward costs. Upon receipt of this written request, the department will review the validity of these changes.

3. Crown Share of Costs:
   Starting with the April 2010 IABP, actual reported costs will be used to determine the annual capital, operating and custom processing fee cost adjustments for each client/facility. The monthly go-forward estimated costs for each client/facility will also be populated from the actual cost calculations at IABP.

   The Crown share of the actual capital costs, operating costs and custom processing fees will be calculated using the actual FERR for each client/facility. The concept of updating the actual capital costs and custom processing fees and implementing the monthly go-forward estimates at IABP remains the same, except being applied at a client/facility level. The concept of updating the actual operating costs (currently adjusted once a year in the February billing period) and implementing the monthly go-forward estimates will be processed at IABP. Further adjustments resulting from amendments filed in any month after IABP will be subject to prior period interest charges. These changes handle operating costs in the same manner as capital costs and custom processing fees. Since only owners will receive monthly estimated operating cost deductions, the process to recapture operating costs from non-owners will be eliminated.

4. Annual Allowable Cost Restrictions (AACR):
   The annual Crown share of actual allowable costs will be determined for each client/facility. If the annual Crown share of actual costs (capital + operating + custom fees) exceeds the annual royalties payable at the ERCB facility level, there will be a restriction resulting in an AACR adjustment shown on the invoice.