ENERGY

Petroleum Plaza – North Tower
9945 – 108 Street
Edmonton, Alberta
Canada T5K 2G6

06-10

GAS ROYALTY CALCULATION INFORMATION BULLETIN October 2006

PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for August 2006, refer to Attachments 1, 1A, 2, 2A, and 3.

B. NOTICES

Termination of the Deep Gas Royalty Holiday Program (DGRHP) and Implementation of a new Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW)

On August 22, 2006, Alberta Energy (DOE) announced the termination of the existing royalty holiday program for deep natural gas wells and the implementation of a new adjustment program for deep marginal natural gas wells as described in Information Letter 2006-26. The changes are effective as of September 1, 2006.

Phasing out the existing Deep Gas Royalty Holiday Program (DGRHP)
Wells that are drilled or deepened, before April 1, 2010, on a Crown Agreement that has a term commencement date earlier than September 1, 2006 and meets the DGRHP criteria will continue to be eligible for exemption under the existing DGRHP, with the following exceptions:

- Oil and oil sands wells, which are spudded or commence drilling on or after September 1, 2006, are no longer eligible for exemption under the DGRHP.
- Commencing April 1, 2012 all wells that have remaining benefits under the DGRHP will have the benefits rolled into the new program, and will be subject to a minimum 5% royalty rate.

Clients who are eligible for an exemption under the DGRHP may elect to receive adjustments under the new Royalty Adjustment Program for Deep Marginal Gas Wells (RAPDMGW) rather than receive an exemption under the DGRHP. The election must be made in writing by the Designated Representative identified on the Crown Agreement or by the well licensee prior to spudding or commencement of drilling and sent to:

Attention:
Gas Royalty Calculation Unit
Royalty Programs
8th floor NPP
9945 - 108 Street
Edmonton, AB T5K 2G6

The election must include the Crown Agreement number, the term date and the legal land description. If a well license has been issued by the Energy and Utilities Board (EUB) the license number and the unique well identifier must also be included. In those situations where the well information is not available at the time of election, the Designated Representative or well licensee/operator must supply the well event identifier when it is available. The department will provide written notification regarding the well's eligibility.

New Program: Royalty Adjustment Program for Deep Marginal Gas Well (RAPDMGW)

Highlights of Program

- The royalty adjustment begins on the first day of the month in which the royalty payable on gas production obtained from the well is due.
- Royalty adjustments must be used within 10 years following the finished drilling date applicable to the drilling or deepening of the well and will terminate if the well is abandoned.
- Wells are subject to a minimum 5% royalty rate each month.
- Royalty adjustments are limited to a maximum of $3,600,000 per well regardless of the number of producing zones.
- Determination of the royalty adjustment amount is calculated on the vertical and horizontal depth of the well.
- A wells average daily production cannot exceed the qualifying production rate (QPR) during each 12 month reporting period.

Qualifying Criteria

To receive royalty adjustments under the RAPDMGW a well must:

- Be drilled or commence drilling on a Crown Agreement with a term commencement date on or after September 1, 2006,
- Be drilled or deepened in a drilling spacing unit that is not wholly or partly within the boundaries of a designated pool,
- Be drilled into a producing zone, the top of which is greater than a vertical depth of 2500 meters,
- Not have average daily production that exceeds the QPR during each 12 month reporting period at any point during the adjustment entitlement.

Wells that do not qualify for RAPDMGW include:

- A well completed in a drilling spacing unit containing wells that previously received a royalty exemption or royalty adjustment under prior regulations or Sections 10 -11 of Schedule 8 of the *Natural Gas Royalty Regulations, 2002*,
- A well whose production of crude oil or oil sands is exempt from royalty under the *Third Tier Exploration Well Royalty Exemption Regulation* and that exemption has not wholly been revoked,
- Off target wells,
- A well that produces oil either alone, or with gas at a gas-oil ratio of less than 1800:1,
- A well that produces oil sands, other than a gas well as defined in the *Oil and Gas Conservation Regulations*,
- A well that is within the pool boundaries as designated by the EUB as at June 1, 1985.

Determining whether a well qualifies

The process and technical analysis of whether a well qualifies for RAPDMGW will be completed in the same manner as DGRHP wells. An application is not required. If the department determines that the well meets all of the qualifying criteria, except the qualifying production rate, the department will perform a preliminary calculation of the average daily production using available well production data at that time and compare this against the QPR described below.

If it appears that the average daily production will be below the calculated QPR, the well will tentatively be approved for royalty adjustment under the program. A calculation of the QPR using production data for the 12 month reporting period will be completed when the data is available.

The calculation of the Average Daily Production (ADP) & Qualifying Production Rate (QPR)

The average daily production (ADP) is determined by dividing the quantity of natural gas and field condensate from all the drilling occurrences that share the same surface location (production from all zones in a multi-zone well bore) within the 12 month period and dividing this quantity by the number of days in the period (note these are not operating days but calendar days).

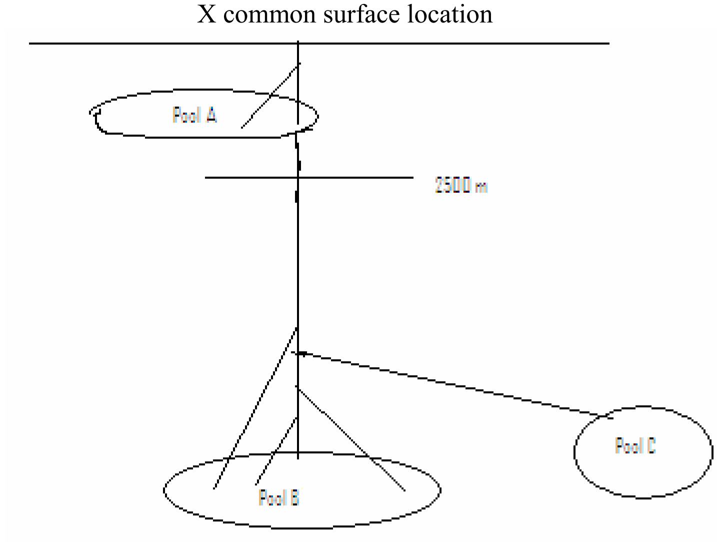
Note: Field condensate volumes will be expressed as a gas equivalent using a conversion rate of 1,000 cubic meters of natural gas per cubic meter of condensate.

The QPR will continue to be re-calculated, each reporting period for all non-statute barred years, for the entire 10 year entitlement period for the well regardless of whether the entire adjustment has been taken. If at any point the ADP exceeds the QPR the entire adjustment will be revoked.

As shown in the diagram below the production included in the determination of the average daily production would include all the drilling occurrences (each leg from the initial well is considered a drilling occurrence) that share this common surface location.

Diagram 1

X common surface location



The QPR was established to reference an economic threshold for wells at varying depths. For the initial six month analysis and first 12 month period the QPR is based on the following formula:

For wells drilled > 2,500 m but ≤ 3,500 m

$$\text{QPR} = \left[1.1327\text{e}^3\text{m}^3 + \left\{ .0850\text{e}^3\text{m}^3 \text{ x } \frac{(\text{MD} - 2500\text{m})}{100\text{m}} \right\} \right] \text{ x } \left[\frac{\text{MD}}{100\text{m}} \right] \leq 3500 \text{ m}$$

For wells drilled > 3,500 m

$$\text{QPR} = \left[1.9822\text{e}^3\text{m}^3 + \left\{ 0.1133\text{e}^3\text{m}^3 \text{ x } \frac{(\text{MD} - 3500\text{m})}{100\text{m}} \right\} \right] \text{ x } \left[\frac{\text{MD}}{100\text{m}} \right] > 3500 \text{ m}$$

Where:
QPR = the qualifying production rate for the well
MD = the measured depth of the well on the last day of the applicable period

The QPR for the second production year will be adjusted to 80% of the first year QPR and 68% of the first year QPR for the third and all subsequent years.

If a well has an acid gas content of more than 15%, the QPR may be adjusted using the following formula:

Adjusted QPR = QPR / [100% - (H_2S%+CO_2%-15%)]

Where:

QPR = the qualifying production rate for the well
H_2S and CO_2 = the % of hydrogen sulphide and carbon dioxide contained in the raw gas stream, respectively.

It is the responsibility of the well operator/licensee to provide documentation for the department's review, such as a gas analysis report signed by a professional engineer, in cases where the well operator/licensee is seeking to have the adjusted QPR applied.

Determination of Royalty Adjustment
The value of the royalty adjustment is determined by both the vertical and horizontal depth of the well.

The vertical depth is determined by using the distance from the surface location Kelley bushing to the base of the natural gas producing interval in the deepest zone in paying quantities. The vertical depth, below 2,500 meters, determines the qualifying interval (QI) used in calculating the cumulative adjustment amount as shown in Attachment 5.

The measured depth is the longest distance in meters measured along the well bore from the Kelley bushing to the base of a natural gas producing interval that is producing in paying quantities. The measured depth minus the wells vertical depth is the non-vertical depth. The non-vertical depth determines the incremental value, as per Attachment 5, to be added to calculate the remaining adjustment value for the well.

In diagram 1 the QI would be the true vertical depth (TVD) pay base of pool B. The measured depth would be calculated to the pay base of pool C. The adjustment amount would be TVD (pool B) + [MD (pool C) – TVD (pool B)] x $1,000 m.

The provincial weighted average gross up factor of 1.72392 will be applied against the adjustment amount determined by the formula above.

Revocation of Royalty Adjustment if QPR exceeded
If at any point during the royalty adjustment entitlement period the average daily production of the well exceeds the calculated qualifying production rate, the royalty adjustment will be revoked. The effective date of the revocation will be the royalty adjustment commencement date unless the well has been deepened after this date and the excess production is a result of the deepening. In this case the effective date for revocation will be the date the well was deepened.

Any Crown royalty charges that were offset by the adjustment will be reversed and royalties' payable on the natural gas, field condensate and gas products will be recalculated as if the royalty adjustment never arose. Interest will apply to the recalculation of royalties.

If a royalty adjustment is revoked because the QPR was exceeded, the royalty client must provide supporting documentation for the adjusted QPR calculation (e.g. Gas analysis report as described above). The department will review the documentation and determine whether the royalty adjustment will be reinstated.

Processing time lines

The time line for processing royalty adjustments will be similar to those for the DGRHP. The department will inform the operator and licensee in writing when the well qualifies, the royalty adjustment amount, and other pertinent data. Clients may also track the progress of eligible wells on the internet through a well ‘process status’ spreadsheet similar to the spreadsheet for the DGRHP. See the Natural Gas Royalty Guidelines, 2006, Chapter V, Section 1 for a complete description of the available “process statuses.”

Reporting

The department determines the monthly royalty adjustment amount based on the volumetric production and SAF/OAF allocation reporting. In order for a royalty adjustment to be applied against a well, the well must be reported at a single well level, except in the case where only a portion of the well qualifies for a royalty adjustment. In these situations the department will advise clients how to report the production.

Invoices/statements

The department will automate the processes relating to this program in the near future. Until such time, the following processes will apply:

- In the first billing period, relating to the production reported for the well, the 5% royalty will not be charged. There will be a one month lag.
- In the following billing period the minimum 5% royalty rate will be calculated and charged. Interest will be charged on underpayments of royalties.
- RAPDMGW wells will appear on the royalty exemption statement as DGRHP wells. The remaining royalty adjustment balance shown on the exemption statement will be overstated by the 5% royalty which was not charged in the first billing period.
- Monthly, the department will send out a revised statement to all participants in the well showing the actual remaining royalty adjustment balance.

For additional information, please contact RoseAnn Summers, Manager, Royalty Billing at (780) 422-6684 or Tracy Wadson, Team Lead, Royalty Programs at (780) 422-9240.

C. MONTHLY INFORMATION

August 2006 Royalty Due November 30

- **Royalty clients are to remit the total amount payable shown on the November 2006 Statement of Account by November 30, 2006**. If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The November 2006 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your August 2006 Invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of August 2006 if it is paid in full by November 30, 2006.

- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

  Note: If the due date falls on a non-business day, the next business day will apply as the due date.

- Cheques are payable to the Minister of Finance, Province of Alberta.

September 2006 VA4 Due November 15

The VA4 forms for the production month of September 2006 are due in the department offices by November 15, 2006.

Note: If the due date (15th) falls on a non-business day, the next business day will apply as the due date for VA4 forms.

September 2006 Production Reporting

September 2006 production reporting is submitted through the Registry. The deadline for submission of SAF, OAF, and Volumetrics is posted in the Petroleum Registry of Alberta website “Reporting Calendars” under Bulletin Board.

Changes to this calendar will be posted on the Registry web site home page in “Broadcast Messages.”

Interest Rate October 2006

Alberta Energy’s interest rate for October 2006 is 7.00%.

July Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the July 2006 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$3,896,544.18	($2,846,418.30)	$1,050,125.88

July Penalty Charges

The revised penalty table below shows at the form level, the total penalty charges and reversals, for the July 2006 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2006/07
AC2	$44,100	($5,600)	$38,500
AC4	$200	$0	$200
AC5	$1,800	$0	$1,800
GR2	$0	$0	$0
NGL1	$0	$0	$0
VA2	$0	$0	$0
VA3	$0	$0	$0
VA4	$100	$0	$100
Total	**$46,200**	**($5,600)**	**$40,600**

Alberta Royalty Tax Credit Program Quarterly Rate

For the fourth quarter of 2006, commencing October 1, 2006, the royalty tax credit rate will be .2500. This rate is based on a royalty tax credit reference price of $430.81 per cubic metre as set by the Department of Energy. The Alberta Royalty Tax Credit rates for the past year were:

Third Quarter, 2006	.2500
Second Quarter, 2006	.2500
First Quarter, 2006	.2500
Fourth Quarter, 2005	.2500

If you have any questions, please contact Alberta Finance, Information Services at (780) 427-3044. [Toll-free long distance is (780) 310-000-427-3044].

Gas Royalty Calculation Support

Gas Royalty Calculation staff will be available monthly to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to call Richard Stokl, Manager, Client Services (780-422-9258) or e-mail richard.stokl@gov.ab.ca two business days before the meeting date to arrange an appointment. The November through December schedule is as follows:

Where:
AMEC Place
Room 437, 801-6 Avenue SW
Calgary, Alberta
Phone: 403-297-8954
(Industry must go to the 3rd Floor Reception upon arrival to sign-in and be given a visitor tag)

When – 10 am to 3 pm
November 23, 2006
December 13, 2006

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role start date with no end date, then that BA can receive allocations from the stated start date forward.
- If a BA has a WIO role start and end date, then they can only receive allocations from the stated start date until the end date. Any allocations after the end date will be rejected.
- If a BA does not have a WIO role start date, then that BA cannot receive allocations at all.

Please contact Client Registry at (780) 422-1395 if you have any questions regarding the information supplied on this listing.

Projects/Blocks

If information is required on Projects or Blocks, please contact Isabelle Warwa at (780) 427-8952.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at (780) 422-1395.

The following is a list of struck, cancelled, dissolved, and revived clients:

Company Name	Client ID	Struck Date
419022 Alberta Ltd.	A05J	September 2, 2006
690462 Alberta Ltd.	0XD1	October 2, 2006
AMH Group Ltd.	0MB1	September 2, 2006
Argus Resources Ltd.	0BP6	October 2, 2006
Duart Developments Ltd.	0F4N	October 2, 2006
E2 Environmental Alliance Inc.	0B2K	October 2, 2006
Ener-West Projects Ltd.	0HX5	September 2, 2006
Enviro Abled Solutions Inc.	A0Y9	September 2, 2006
Fairholme Resources Ltd.	0F8L	September 2, 2006
Fwdstep Resources Limited	0Z0F	October 2, 2006
Harp Resources Ltd.	0G6J	October 2, 2006
Noyes Supervision (1981) Ltd.	0T33	October 2, 2006
Redfern Resources Ltd.	0L7M	October 2, 2006
Shell Chemicals Canada Ltd.	A229	October 2, 2006
Universal Ford Lincoln Sales Ltd.	646C	October 2, 2006
Vectra Ltd.	0EC3	October 2, 2006
Westridge Petroleum Corp.	0FJ2	September 2, 2006
Company Name	**Client ID**	**Cancelled Date**
1205721 Ontario Inc.	0RH2	October 2, 2006
Canadian Spooner Resources Inc.	0293	September 2, 2006
Placer Dome Inc.	0HG2	October 2, 2006
Company Name	**Client ID**	**Dissolved Date**
Bowness Hotel and Leasing Limited	A1BA	September 13, 2006
K-Mac Consulting Services Ltd.	0CY7	September 25, 2006
Moonshine Resources Ltd.	A11P	September 12, 2006
Planet Recycle & Disposal Inc.	A14E	September 18, 2006
Procor LPG Storage Inc.	0R70	September 21, 2006
Q.E.C. Services Inc.	A0WG	October 13, 2006
Company Name	**Client ID**	**Revived Date**
236655 Alberta Ltd.	0T7F	October 6, 2006
Ener-West Projects Ltd.	0HX5	October 4, 2006
Longview Resource Management Corporation	0HY4	September 8, 2006

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Operating Costs Subject to Recapture

Operating costs subject to recapture reports for the 2005 production year were produced effective the April 2006 billing period invoice issued in June 2006, have been issued each month since then and has been charged in the August 2006 invoice issued in October 2006.

For more information, please contact your applicable Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

Statutory Requirement and Recalculation of 2002 Royalty

A production year becomes statute barred on December 31st, four years after the end of a production year. Once a year has become statute barred, calculation or recalculation of royalty does not occur on a monthly basis.

Section 38 of the Mines and Minerals Act provides for recalculation of royalty that can be initiated in either of two ways:

a) On the department's initiative in conjunction with an audit or examination; or
b) At the request of a royalty payer.

Audits in Progress

Non-operator partners are advised that certain 2002 capital cost and custom processing adjustment factor (CPAF) and reporting discrepancy audits are currently in progress. It is anticipated that these audits may be completed before December 31, 2006. However, should circumstances require that these audits be completed in 2007, a listing of the affected EUB facilities will be included in the December 2006 Information Bulletin.

Royalty clients are also reminded that amendments received by the department in the fourth year following the production year may be subject to audit. If the amendments are received late in the fourth year and insufficient time is available for the department to commence a review of the amendments prior to the end of the year, the department reserves the right to commence the audit at the beginning of the fifth year.

If you have any questions, please contact Chris Lawton of the Compliance & Assurance group at (403) 297-6746.

Industry Recalculation of 2002 Royalty

Industry initiated royalty recalculation requests for the 2002 production year must be submitted in writing to the attention of Richard Stokl, Manager of Gas Royalty Client Services. This request must be received by the department on, or before, December 31, 2006 and it should include the following:

- Identification of the recalculation facility or facilities;
- The reason for the recalculation;
- An order of magnitude estimate, i.e. the approximate amount of the royalty impact;

- Identification of the royalty clients that may be impacted by the request;
- The time lines for recalculation preparation and submission to the Crown including a reasonable time for the Crown to review the submission; and
- Confirmation that the affected partner(s) have been notified.

If you have any questions regarding this process please contact your Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

Current RMF2 Listing Report

The August 2006 invoice package included a Current RMF2 Listing report issued only once to royalty clients who are assignors on the RMF2 form. In the future royalty clients may request an updated report as required, by contacting their Gas Royalty Client Services portfolio representative.

The Current RMF2 Listing report identifies the royalty clients' active RMF2s currently in our system, including the ones with an effective date range in an open year. Please see Attachment 4 for a sample of this report.

If an RMF2 is no longer required for a stream ID, the assignor must submit an RMF2 form to terminate the reassignment of volumes. If you have any questions, please contact your Gas Royalty Client Services portfolio representative, as identified in Section F of this bulletin.

Changes to the UOCR Estimates

To avoid huge swings in the annual adjustment of estimated operating costs to actual operating costs, facility operators currently can request a change to their estimated processing rate for new non-designated facilities.

Effective September 2006, EUB facility operators may apply through a written request to the department for a change to a facility's estimated UOCR. This new process applies to any component for Designated and non-Designated facilities whose rate is based on actual operating costs reported on the AC4. In other words, any estimated component rate for a designated facility can be changed, but only the estimated processing rate for a non-designated facility can be changed as their gathering and compression rates are derived from the operating cost survey and promoted through annual change factors.

The EUB facility operator must provide the following information to determine an estimated component (processing, gathering, compression) rate, effective for the entire rate year (Feb to Feb exclusive):

EUB Facility ID;

- Operator name and ID;
- Estimated operating cost amount ($) for each component;
- Estimated energy adjusted gas equivalent (EAGE) volumes;
- Production year.

For more information, please contact your applicable Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Alberta Energy Internet

Prices, Royalty Rates, and Transportation Information are available on the Alberta Energy Internet address: http://www.energy.gov.ab.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Calculation Information Bulletins and Information Letters are also available on the Alberta Energy Internet address: http://www.energy.gov.ab.ca, from "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

The Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Service teams. Listed below is the portfolio breakdown along with Client Service Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at (780) 644-1202.

Business Associate	Phone Number and E-mail Address	Team Lead
Numbered companies, A, B & L	(780) 644-1201 GRCST1@gov.ab.ca	Mary Spearing
C – G	(780) 644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	(780) 644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q – Z	(780) 644-1204 GRCST4@gov.ab.ca	Kamal Rajendra

Gas Royalty Reception: (780) 427-2962
Fax: (780) 427-3334 or (780) 422-8732
Alberta Toll Free: (780) 310-0000
Hours of operation are 8:15 a.m. to 4:30 p.m.
Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer.

Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets. You would not be entitled to information regarding business for TSP Exploration that is prior to the asset purchase.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone (403) 297-5514
Fax (403) 297-5400

Calgary Information Centre

300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone (403) 297-6324
Fax (403) 297-8954

Alberta Royalty Tax Credit Information

Alberta Finance, Tax and Revenue Administration
Tax Services
Telephone: (780) 427-3044
Alberta Toll Free: (780) 310-0000
Fax: (780) 427-5074
For further information, please contact Tax Services at (780) 427-9425.

Deen Khan
Director, Gas Royalty Calculation
Gas Development

Attachments

2006 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butanes ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	9.52	9.56	9.56	9.33	9.11	9.10	9.14
FEB	7.38	7.36	7.36	7.58	7.58	7.58	7.59
MAR	6.47	6.46	6.46	6.67	6.71	6.74	6.76
APR	6.18	6.17	6.17	6.31	6.31	6.36	6.36
MAY	5.71	5.70	5.70	5.77	5.74	5.76	5.77
JUN	5.29	5.26	5.26	5.57	5.64	5.67	5.70
JUL	5.22	5.19	5.19	5.48	5.54	5.57	5.58
AUG	5.84	5.81	5.81	6.06	6.10	6.13	6.15
SEPT							
OCT							
NOV							
DEC							

Natural Gas and NGLs Select Prices for 2006

Commodity	2006
New Methane	1.419 $/GJ
Old Methane	0.418 $/GJ
New Ethane	1.419 $/GJ
Old Ethane	0.418 $/GJ
Propane	1.419 $/GJ
Butanes	1.419 $/GJ
Pentanes plus	50.73 $/m3

Royalty Factors for Pentanes plus

	Base	Marginal
New Pentanes	22	35
Old Pentanes	22	50

DETAIL OF THE AUGUST 2006 GAS AND ISC REFERENCE PRICES

	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	6.166	6.152	6.293	6.289	6.297	6.290
Deductions: Intra – Alberta Transportation	0.250	0.266	0.152	0.107	0.082	0.063
Marketing Allowance	0.012	0.012	0.012	0.012	0.012	0.012
Price Before Pipeline Factor	5.904	5.874	6.129	6.170	6.203	6.215
Pipeline Fuel/Loss Factor	.989	.989	.989	.989	.989	.989
Price before Special Adjustment	5.842	5.812	6.065	6.105	6.137	6.150
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	5.842	5.812	6.065	6.105	6.137	6.150
Amendments: Carry forward (from previous RP month)	0.005	-0.001	-0.003	-0.003	-0.005	0.002
Prior Period Amendment Adjustment (current RP month)	-0.003	-0.002	-0.001	-0.001	-0.001	-0.001
Calculated RP after Amendments	5.844	5.809	6.061	6.101	6.131	6.151
AUGUST 2006 Reference Price	**5.84**	**5.81**	**6.06**	**6.10**	**6.13**	**6.15**
Difference = value carried forward to next RP month	0.004	-0.001	0.001	0.001	0.001	0.001
Adjusted IATD (before Prior Period Amendments)	n/a	0.263	0.150	0.106	0.082	0.062
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	n/a	0.263	0.150	0.106	0.082	0.062

2005 Weighted Average Reference Price ($/GJ)
7.935

2005 Weighted Average OMAC ($/GJ)
0.023

2006
NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Par Price ($/GJ)	Propane Floor Price ($/m3)	Butanes Reference Price ($/m3)	Butanes Par Price ($/GJ)	Butanes Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	9.33	9.33	289.22	9.11	240.07	394.52	9.10	329.84	484.39	477.02	27.53
FEB	7.58	7.58	248.16	7.58	213.28	370.63	7.58	279.57	468.40	441.89	29.48
MAR	6.67	6.67	254.40	6.71	213.86	362.89	6.74	272.66	468.85	457.27	31.39
APR	6.31	6.31	286.26	6.31	248.88	390.67	6.36	290.57	545.33	524.82	25.41
MAY	5.77	5.77	279.81	5.74	247.11	376.44	5.76	283.32	529.03	507.26	24.31
JUN	5.57	5.57	287.72	5.64	258.60	377.94	5.67	295.08	557.91	516.67	21.78
JUL	5.48	5.48	313.36	5.54	281.70	402.10	5.57	315.61	564.17	538.62	18.77
AUG	6.06	6.06	305.03	6.10	275.34	402.10	6.13	317.45	530.10	511.93	14.09
SEPT											
OCT											
NOV											
DEC											

ANNUAL SULPHUR DEFAULT PRICE				
2001	2002	2003	2004	2005
$0.28	$6.74	$30.97	$31.98	$33.98

2006
NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANES (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW. (per m3)
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	-0.90	13.92	10.05	18.08	18.72	-1.58	-33.18	-18.57	17.78	14.75	35.26	16.39	15.50
FEB	24.88	25.25	34.62	26.47	10.17	-2.24	-57.23	-19.17	18.42	13.68	31.79	18.91	15.50
MAR	14.23	10.00	32.47	4.43	12.33	6.56	3.05	-2.25	20.08	16.58	22.76	19.67	15.50
APR	16.82	16.81	36.92	26.20	8.13	4.05	4.42	3.86	18.80	24.73	22.81	27.82	15.50
MAY	21.44	17.83	34.47	26.88	7.50	0.28	-5.71	1.91	17.91	17.74	17.30	23.36	15.50
JUN	43.47	23.21	58.72	48.53	11.04	8.25	3.62	3.89	39.43	25.73	31.26	24.21	15.50
JUL	25.15	20.49	48.28	19.48	14.52	5.93	12.23*	6.56	31.03	17.24	30.26	23.09	15.50
AUG	22.34	13.57	22.42	12.02	6.13	-0.40	-13.90	4.17	5.48	6.47	11.26	14.65	15.50
SEPT													
OCT													
NOV													
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butanes obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

* Current month calculated allowance is based on an estimate.

<u>Note:</u> For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS

NGL REFERENCE PRICES	AUGUST 2006		
	Propane	*Butanes*	*Pentanes*
Price before amendments	305.026878	402.100032	530.102807
Opening Rollover (from prior business mth)	0.000412	0.002569	-0.004444
Prior Period Amendment Adj. (NGL-1)	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	0.000000	0.000000	0.000000
Published Reference Price	**305.03**	**402.10**	**530.10**

TRANSPORTATION ALLOWANCES	AUGUST 2006											
	Pentanes Plus				Propane and Butanes				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	-0.004119	0.001613	0.003024	-0.001185	0.004544	0.000942	-0.000096	-0.004138	-0.003781	-0.004311	0.000250	0.002425
Prior Period Amendment Adj. (NGL1)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Prior Period Amendment Adj. (NGL-100)	0.000000	0.000000	0.000000	0.000000	-0.183257	0.000000	-0.135763	0.000000	0.000000	0.000000	0.000000	0.000000
Total Amendment Effect	-0.004119	0.001613	0.003024	-0.001185	-0.178713	0.000942	-0.135859	-0.004138	-0.003781	-0.004311	0.000250	0.002425
Calculated Transp. Differential	22.340859	13.568769	22.417705	12.018230	6.312295	-0.404840	-13.761013	4.173616	5.482970	6.475251	11.257573	14.644271
Calculated Transp. Differential after Total Amendments	22.336740	13.570382	22.420729	12.017045	6.133582	-0.403898	-13.896872	4.169478	5.479189	6.470940	11.257823	14.646696
Published Transportation Allowance	**22.34**	**13.57**	**22.42**	**12.02**	**6.13**	**-0.40**	**-13.90**	**4.17**	**5.48**	**6.47**	**11.26**	**14.65**

*Any estimates represented by (*) are calculated as the weighted average of the other regions for the same spec product transportation allowance, since the region is zero. The weightings are based on the previous year's production.

2006
ROYALTY RATES

MONTH	METHANE-OLD (% per GJ)	METHANE-NEW (% per GJ)	ETHANE - OLD (% per GJ)	ETHANE - NEW (% per GJ)	PROPANE (% per m^3)	BUTANES (% per m^3)	PENTANES – OLD (POL) (% per m^3)	PENTANES - NEW (PNE) (% per m^3)
JAN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.02226	33.61748
FEB	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.78553	33.50757
MAR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.89365	33.55777
APR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.29347	33.74340
MAY	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.19978	33.69990
JUN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.25078	33.72358
JUL	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.36282	33.77559
AUG	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	47.22532	33.71176
SEPT								
OCT								
NOV								
DEC								

ENERGY

CURRENT RMF2 LISTING

Invoice #:00000043170

Issue Date: 2006-06-30
Royalty Client: 0AA0
Name: NONAME OIL COMPANY

Royalty Payer: 0AA0
Name: NONAME OIL COMPANY
Address: PO BOX 1234 STN Q
CALGARY AB T2T 5N2
CA

Stream	Effective Date	Term Date	Last Used	Assignee		Percentage
AB IS 12345	2004-01		2005-11	0AA0	NONAME OIL COMPANY	51.0000000
				0BB0	BIG OIL AND GAS COMPANY	49.0000000
AB UN 12345	2004-01		2006-03	0AA0	NONAME OIL COMPANY	75.0000000
				0BB0	BIG OIL AND GAS COMPANY	25.0000000
AB WG 123456	2004-01	2006-05	2006-02	0AA0	NONAME OIL COMPANY	75.0000000
				0BB0	BIG OIL AND GAS COMPANY	25.0000000
AB WI 102060401401W400	2004-01		2005-11	0AA0	NONAME OIL COMPANY	51.0000000
				0BB0	BIG OIL AND GAS COMPANY	49.0000000

******* End Of Report *******

Value of Adjustment per Qualified Well

Depth of Qualified Well to Base of Natural Gas Producing Interval in Deepest Zone Producing in Paying Quantities	Cumulative Value	Incremental Value
(metres)	($000)	($/metre)
2500	0	1000
3000	500	1000
3500	1000	1000
4000	1500	1300
4500	2150	1300
5000	2800	1600
5500 or deeper	3600	