

**GAS ROYALTY CALCULATION
INFORMATION BULLETIN
February 2004**

04-02

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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 December 2003, refer to [Attachments 1, 1A, 2, 2A, and 3](#).

B. NOTICES

Par Price Calculation Change

Effective January 2004 production, the Department of Energy is changing the methodology used to calculate par prices for natural gas and natural gas liquids. The new method uses current month's reference prices instead of previous month's reference prices. This change will ensure that price sensitive royalty rates for natural gas and natural gas liquids are more representative of the market price of natural gas and natural gas liquids in the month of production. January 2004 royalty rates for natural gas and natural gas liquids (excluding pentanes plus) are not affected by this change since rates are at maximum. There will be a small increase in the pentanes plus royalty rate but after discussion and agreement with industry representatives this impact has been determined to be immaterial.

For additional information, contact Bill Zanewick at (403) 297-5465.

Weighted Average Aggregator Overhead Marketing and Administration Charges (OMAC)

For Gas Corporate Average Price (CAP) filers, when determining the netback value, the weighted average OMAC type charges may be deducted for sales to non-designated aggregators. Refer to Chapter III, Section 1.7.3 of the Principles and Procedures for additional information.

The Weighted Average Aggregator OMAC (\$/GJ) for 2003 is \$0.021. Refer to Chapter III, Sections 1.3 and 1.4 of the Principles and Procedures for additional information.

Annual Weighted Average Gas Reference Price

The Annual Weighted Average Gas Reference Price for 2003 is \$5.83. This price is used in the calculation to determine the 2003 minimum price for the Gas Corporate Average Price. Refer to Chapter III, Section 1.7 of the Principles and Procedures for additional information.

C. MONTHLY INFORMATION

December 2003 Royalty Due March 31

- **Royalty clients are to remit the total amount payable shown on the March 2004 Statement of Account by March 31, 2004.** 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 March 2004 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your December 2003 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 December 2003 if it is paid in full by March 31, 2004.
- 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, payments will be accepted on the next business day.

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

January 2004 VA4 Due March 15

The VA4 documents for the production month of January 2004 are due in the Department offices by March 15, 2004.

NOTE:

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

January 2004 Production Reporting

January 2004 production reporting is submitted through the Registry. The deadline for submission of SAF, OAF, and Volumetrics is posted in the Registry Reporting Calendar at:

http://www.petroleumregistry.gov.ab.ca/PRA/Bulletin_Board/Calendar/default.htm

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

Interest Rate February 2004

The Department of Energy’s interest rate for February 2004 is 5.25%.

November Provisional Assessment Charge

The net Provisional Assessment Charge for the November 2003 billing period was (\$4,647,485.26). This includes \$18,860,281.96 in first time provisional assessments and (\$23,507,767.22) in reversals of provisional assessments for all production periods.

November Penalty Charges

The following are the Penalty Charges by form type for the November 2003 billing period:

FORM	Penalties Charged
AC2	\$6,200
AC4	\$0
AC5	\$22,800
GR2	\$0
NGL1	\$0
VA2	\$0
VA3	\$0
VA4	\$0
Total Charged	\$29,000
Total Reversed	(\$6,900)
Net Penalties Charged for 2003/11	\$22,100

Alberta Royalty Tax Credit Program Quarterly Rate

For the first quarter of 2004, the Alberta Royalty Tax Credit rate will be .2500. This rate is based on a royalty tax credit reference price of \$370.86 per cubic metre. The Alberta Royalty Tax Credit rates for the past year were:

Fourth Quarter, 2003	.2500
Third Quarter, 2003	.2500
Second Quarter, 2003	.2500
First Quarter, 2003	.2500

If you have any questions, please contact Kent Nelson of Tax Services at (780) 427-9425, ext. 44066.

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The Client ID listing can be found on the Internet at the following address:

www.energy.gov.ab.ca

The listing, which is updated monthly for active clients, also includes clients who are inactive, struck, or terminated since January 1998.

Please note the Client ID listing (Post Registry) corresponds with the implementation of the Registry. For effective dates of active and amalgamated clients prior to September 1, 2002, please refer to the Client ID listing (Pre Registry).

If you require information before January 1998 regarding the status of a Client ID, please call Gas Royalty Client Services using the phone numbers as described in Section F. The Department would like to remind those browsing the site to note the effective and termination dates of the Client IDs.

Projects/Blocks

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

Struck Clients

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 dissolved clients:

Company Name	Client ID	Dissolved Date
Enerplus Acquisition Inc.	A0KT	January 8, 2004
Achieva Petroleum Corporation	0RR2	January 28, 2004
Scottsdale Resources Ltd.	0R3W	January 30, 2004
Paragon Petroleum Corporation	0LC4	January 19, 2004
Terragrande Energy Limited	0N0P	January 30, 2004
814471 Alberta Ltd.	0D5X	January 30, 2004
Marathon Canada Limited	0AL2	January 19, 2004

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 Department Internet site at:

www.energy.gov.ab.ca

E. REMINDERS

Submission of Production Year 2003 Allowable Cost (AC) and Corporate Average Price Calculation (VA) Forms

Royalty clients are advised that Allowable Cost forms (AC1, AC2, AC3, AC4, and AC5) and Corporate Average Price Calculation forms (VA2 and VA3) for the 2003 production year should be submitted to the Department for processing.

The form due dates are as follows:

<u>Form</u>	<u>Due Date</u>
AC1	March 1, 2004
AC4	March 31, 2004
AC2	April 30, 2004
VA2	April 15, 2004
VA3	April 15, 2004
AC5	May 15, 2004
AC3	May 15, 2004

Appendix C of the Natural Gas Royalty Guidelines, June 2003, outlines the form edits for paper submission documents. Electronic form filers should check the Department's Internet site for electronic form edits.

Gas royalty payers and their service providers should go to the Registry to retrieve PDF and text versions of the gas royalty reports such as the Gas Royalty Invoice, Statement of Account, Turnaround Reports, and form reject reports. Clients with reports in UDF and DDF formats can also retrieve their files on the Registry. The following Internet web site identifies all of the Department of Energy's E-transfer systems.

www.energy.gov.ab.ca

If you are amending a facility cost centre operator or setting up a new 2003 facility cost centre, please submit your AC1 document in a timely manner to ensure that you can file your AC4 or AC2 documents without penalty.

Otherwise Flared Solution Gas (OFSG) Report

Please be advised that effective with the November 2003 Billing Period Invoice, the Department will be including along with the monthly invoice, a new report providing the Otherwise Flared Solution Gas (OFSG) Details. The report can be requested via the Registry in either text or PDF format. If you have any questions regarding the information on this report, please contact Ms. Jamie Niles at (780) 422-9264 or Ms. Rose Dykes at (780) 422-8083.

Inclusion of CO2 Removal Costs in the Gas Reference Price

Background:

On September 24, 2002, the Alberta Energy and Utilities Board (EUB) approved Nova Gas Transmission Ltd.'s (Nova) application for implementation of a CO2 Management Service. Nova's application was in response to complaints centered on Nova's practice of accepting onto its transportation system, gas containing greater than 2% by volume of carbon dioxide (CO2). Effective with January 2003 deliveries, Nova stopped accepting system gas containing greater than 2% by volume of carbon dioxide (CO2) unless the shipper had signed a CO2 management service agreement. The overall revenue collected under these agreements is used to offset overall costs of extracting the CO2. Nova is allocated 10% of any excess revenue to a maximum of \$500,000, with the remainder credited to the system-wide revenue requirement in the subsequent year.

The following information identifies how the department will recognize the CO2 Management Service fee, and CO2 Extraction contracts for royalty purposes, effective 2003:

Gas Cost Allowance:

The costs to extract CO2 at a field gas plant are included in the Gas Cost Allowance (GCA), which is an eligible deduction in the calculation of natural gas royalties. The Crown has recognized that the costs are required to make the natural gas marketable and therefore the costs are appropriate for cost allowance. The Department will allow a producer GCA if they incur costs in modifying their plant to extract CO2 prior to delivery to a meter station. However, **CO2 costs or other processing costs incurred downstream of the gas plant are not allowed to be included in GCA, as these costs will be recognized in the Gas Reference Price (GRP) calculation.**

If a gas plant receives payment from Nova to reduce their CO2 content under a CO2 extraction contract, then the incremental operating costs to reduce the CO2 content is not eligible for GCA and must be excluded from the Operating cost reporting on the AC4. If it is not possible to identify the incremental operating costs, then any revenues received from Nova for extracting CO2 must be excluded. If an operator cannot allocate the incremental cost to all facility cost centers (FCC), one of the FCC's must be chosen to reflect the excluded cost or revenue received.

Gas Reference Price:

The fee paid to Nova is a cost incurred downstream of the gas plant and is included in the GRP by adjusting the Intra-Alberta Transportation Deduction portion of the GRP calculation. Allowing CO2 Management Service Billings to reduce the GRP, as long as the same fees are not included in Gas Cost Allowance, recognizes that the service is required to make the gas marketable. The excess revenue generated from the CO2 Management Service Billings over costs is credited back to all shippers through a reduction in the system-wide revenue requirement in the subsequent year.

Corporate Average Price:

Royalty clients that have elected to have their Crown royalty share of raw gas, residue gas, and ethane valued at the Gas Corporate Average Price (CAP) will also be allowed an eligible deduction. A royalty client calculates CAP annually using his own sales for the period. If a CAP client has incurred a CO2 Management Service fee, the Department will accept CAP reporting that includes the CO2 Management Service Billings, as transportation costs incurred by a producer, who is also a shipper, as an eligible deduction. This is consistent with the inclusion of the CO2 Management fee in the Gas Reference Price. CAP filers can include the Billings in Section 2.3 (Total cost incurred by the royalty client to transport the gas reported in column 2.1 within Alberta) of the VA2 form.

If you have any questions, please contact David Isaac at (780) 422-9258.

Update - 1999 Audits in Progress

In accordance with statutory requirements and royalty recalculation guidelines as documented in Information Letter 97-25, non-operator partners are advised that certain 1999 capital cost and custom processing adjustment factor (CPAF) and reporting discrepancy audits are currently in progress. Completion of the audits and royalty recalculations/assessments, if required, will occur in 2004. For a complete listing of the affected EUB facilities, refer to [Attachment 4](#).

Clients are also reminded that in accordance with Information Letter 97-25, 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.

Meter Station Factors

The Department has published in Information Letter 2003-34, retroactive amendments to prescribed Meter Station Factors. The Meter Station Factors affected are September 2002 and September 2003, and the annual prescribed Meter Station Factors effective October 2003.

The Meter Station Factors listing for those retroactive amendments can be found using the following link:

<http://inform.energy.gov.ab.ca>

The Meter Station Factors listing for those prescribed effective October 2003 can be found using the following link:

<http://inform.energy.gov.ab.ca>

Facility Cost Centre (AC1) Amendments

In response to the previous article regarding the RRIR Initiative Proposed Operating Cost Regime Change, the following points regarding Facility Cost Centre (FCC) AC1 amendments need to be clarified.

The following fields are not effective dated. Any change within these fields will be applied to the initial effective date of the FCC:

- Field 5.1 FCC Type
- Field 5.2 FCC Processing Sub-type
- Field 2.8 Associated EUB Facility Code
- Field 2.9 Previous FCC Code
- Field 2.10 Reported EUB Facility Code

Amendments cannot be made to the EUB Facility Code (Field 2.1) for an established FCC. The existing FCC must be terminated and a new AC1 set up with the amended EUB Facility Code, which will result in a new FCC number being assigned.

If any changes to the above fields are required for a closed-out year, the Department must receive a Year End Close Out (YECO) form, or a written request to open the year. Amendments to AC1 documents will not be processed for statute-barred years unless a Department audit is in progress for the facility. For a complete listing of affected EUB facilities, refer to [Attachment 4](#).

If you have any further questions or concerns, please contact Penny White at (780) 415-2679.

Close-out for Operations

Production Year 2001

As prescribed by the Natural Gas Royalty Regulation, 2002, royalty clients are required to file accurate and timely information within specified time frames for a production month or production year. Inherent in the business of gas production is the frequent adjustment and balancing of reported volumes and distribution of costs. These adjustments result in retroactive processing of Industry submitted royalty documents to accurately reflect volumetric ownership and ensure appropriate distribution of costs. To contain the extent of retroactive processing and to facilitate the completion of audits within the legislated time frames, an Operational Close-out process has been established. Normally two years after the end of a production year, that production year is operationally closed. When a production year is operationally closed, the Mineral Revenues Information System (MRIS) will reject any royalty document submitted for a closed out production year after the established close-out dates, unless written authorization is granted by the Department.

Facility Operators and Owners must ensure that correcting documents required to clear unreconciled volumetric discrepancies and to amend the distribution of costs for the closed-out production year are submitted prior to the close-out dates. Facility operators and owners are encouraged to review the following reports produced by the Department to focus on facilities that require immediate attention prior to close-out:

- Rejection Notices
- Summary of Outstanding OAS Volumetric Discrepancies
- Annual Reports
- Reconcile Statement of Account Balances
- Operating Cost Deduction at Facilities with No Capital Ownership or Custom Processing Fees

The close-out dates are as follows for the production year of 2001:

<u>Production Year Primary Documents</u>	<u>Secondary Documents</u>
Close-Out Date	Close-Out Date
January 15, 2004	March 15, 2004

Note: There are only two secondary documents: the Reassignment of Volumes Set Up/Change (RMF2) and the Annual Capital Cost Allowance Reallocation (AC3). All others are primary documents.

Should circumstances warrant the amending of documents for a closed-out year, the Department must receive a Year End Close Out (YECO) form, or a written request to open the year. The YECO form is an alternative to the formal written request. A written request must include the following detailed information:

1. Specific reason for processing documents after operational close-out.
2. List of document types being amended (i.e. OAS, RMF2, AC2).
3. Affected facilities and/or stream IDs (i.e. Gas plant code, facility cost centre code, well event).
4. Copy of letter from the operator to affected partner(s) advising of completion of rework.
5. Estimated dollar impact.
6. Paper copies of the document(s) to be processed.

Operators and owners must ensure that submitted documents meet MRIS edit criteria. Documents that do not meet MRIS edit criteria will be rejected and the client will be notified by a rejection notice. Royalty documents that meet MRIS edit criteria will be processed and will be subject, where applicable, to the following:

- Provisional Assessments
- Recalculation of Royalty
- Interest Calculations
- Re-calculation of Allowable Costs, including the Corporate Effective Royalty Rate (CERR).

Where applicable, results of the processed documents will be reflected in the Crown Royalty Detail Statement, Invoice, and Statement of Account.

The YECO requests together with the applicable royalty documents must be submitted to:

Gas Royalty Client Services
8th Floor, North Petroleum Plaza
9945- 108 Street
Edmonton, Alberta T5K 2G6

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.

Department of Energy Hotline & Internet

Prices, Royalty Rates, and Transportation Information are available on the Department of Energy Internet address or hotline: (403) 297-5430. In addition, both the Gas Royalty Calculation Information Bulletin and Information Letter are also available on the Internet address:

www.energy.gov.ab.ca

Note: To access the sulphur price call the Department of Energy hotline at (403) 297-5430. Wait to hear the recorded list of options, then press #1 on your touch-tone phone for Natural Gas Information. Again, wait for the recorded list of options, then press #3 for Gas Royalty Rates.

Gas Royalty Client Services

Effective March 1, 2003, the Gas Royalty Client Services Help Desk changed to a Business Associate client portfolio system. Listed below is the portfolio breakdown along with Help Desk team leads and new phone numbers. Please note that 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.

	Phone Number	Team Lead
Numbered companies, A, B & L	(780) 644-1201	Mary Carrie
C – G	(780) 644-1202	Renee Matsuba
H – P (excluding L)	(780) 644-1203	Chris Nixon (Feb. 1 to Mar. 1, Matilda Rideout)
Q – Z	(780) 644-1204	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.

Calgary Information Centre

3rd Floor, 801 – 6th Avenue S.W.
 Calgary, Alberta T2P 3W2
 Telephone (403) 297-6324
 Fax (403) 297-8954

Alberta Royalty Tax Credit Information

Alberta 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
 Acting Director, Gas Royalty Calculation
 Gas Development

Attachments

2003 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	5.88	5.84	4.91	6.12	6.11	6.14	6.16
FEB	6.83	6.78	5.84	7.23	7.35	7.36	7.36
MAR	8.94	8.94	6.78	8.96	8.71	8.81	8.80
APR	5.88	5.80	8.94	6.25	6.43	6.48	6.52
MAY	5.73	5.68	5.80	6.09	6.27	6.32	6.35
JUN	5.93	5.86	5.68	6.31	6.48	6.51	6.55
JUL	5.58	5.53	5.86	5.84	5.95	5.99	6.01
AUG	5.08	5.03	5.53	5.33	5.41	5.45	5.47
SEPT	5.19	5.16	5.03	5.38	5.43	5.48	5.51
OCT	4.92	4.88	5.16	5.05	5.08	5.12	5.15
NOV	4.60	4.56	4.88	4.82	4.89	4.93	4.96
DEC	5.11	5.04	4.56	5.40	5.53	5.58	5.62

Natural Gas and NGLs Select Prices for 2003				
Commodity	Post-October 2002 Production	2003		
New Methane	1.252 \$/GJ	1.290 \$/GJ		
Old Methane	0.372 \$/GJ	0.379 \$/GJ		
New Ethane	1.267 \$/GJ	1.290 \$/GJ		
Old Ethane	0.372 \$/GJ	0.379 \$/GJ		
Propane	1.267 \$/GJ	1.290 \$/GJ		
Butanes	1.267 \$/GJ	1.290 \$/GJ		
Pentanes plus	45.30 \$/m3	46.11 \$/m3		
Royalty Factors for Pentanes plus				
	Base	Marginal	Base	Marginal
New Pentanes	22	35	22	35
Old Pentanes	22	50	22	50

DETAIL OF THE DECEMBER 2003 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	5.543	5.509	5.712	5.787	5.805	5.815
Deductions: Intra – Alberta Transportation	0.286	0.304	0.174	0.122	0.094	0.071
Marketing Allowance	0.029	0.029	0.029	0.029	0.029	0.029
Price Before Pipeline Factor	5.228	5.176	5.509	5.636	5.681	5.715
Pipeline Fuel/Loss Factor	0.987	0.987	0.987	0.987	0.987	0.987
Price before Special Adjustment	5.161	5.109	5.438	5.563	5.608	5.642
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	5.161	5.109	5.438	5.563	5.608	5.642
Amendments: Carry forward (from previous RP month)	-0.023	-0.028	-0.003	-0.002	-0.001	0.001
Prior Period Amendment Adjustment (current RP month)	-0.030	-0.041	-0.031	-0.028	-0.023	-0.021
Calculated RP after Amendments	5.108	5.040	5.404	5.533	5.584	5.622
DECEMBER 2003 Reference Price	5.11	5.04	5.40	5.53	5.58	5.62
Difference = value carried forward to next RP month	-0.002	0.000	0.004	-0.003	0.004	0.002
Adjusted IATD (before Prior Period Amendments)	n/a	0.301	0.171	0.120	0.093	0.070
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.012	0.007	0.005	0.004	0.003
Adjusted IATD (after Prior Period Amendments)	n/a	0.313	0.178	0.125	0.097	0.073

Weighted Average Reference Price (\$/GJ)
3.687

Weighted Average OMAC (\$/GJ)
0.018

2003 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	6.12	5.14	214.79	5.36	169.20	276.56	5.43	223.25	317.99	281.72	26.60
FEB	7.23	6.12	263.88	6.11	220.11	284.24	6.14	215.88	339.40	309.39	26.43
MAR	8.96	7.23	237.11	7.35	199.55	267.78	7.36	200.52	327.17	336.01	30.31
APR	6.25	8.96	194.86	8.71	149.60	200.92	8.81	149.88	282.96	309.82	34.70
MAY	6.09	6.25	178.89	6.43	153.53	186.68	6.48	156.47	262.58	272.24	42.57
JUN	6.31	6.09	192.36	6.27	164.11	194.03	6.32	160.82	274.61	249.37	38.69
JUL	5.84	6.31	190.04	6.48	165.96	190.66	6.51	166.10	277.36	262.40	32.59
AUG	5.33	5.84	203.50	5.95	181.90	205.16	5.99	177.80	282.75	268.89	28.75
SEPT	5.38	5.33	194.59	5.41	165.78	210.24	5.45	163.14	237.58	269.67	33.66
OCT	5.05	5.38	204.37	5.43	178.56	226.09	5.48	180.70	250.26	234.96	28.31
NOV	4.82	5.05	177.82	5.08	155.23	236.65	5.12	182.60	269.72	239.96	27.71
DEC	5.40	4.82	194.34	4.89	163.84	246.76	4.93	186.89	292.72	256.45	21.33

ANNUAL SULPHUR DEFAULT PRICE				
1998	1999	2000	2001	2002
\$6.01	\$10.54	\$11.03	\$0.28	\$6.74

2003
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	8.04	8.14	17.04	2.24	6.42	0.10	1.96	5.66	12.73	19.09	23.37	15.47	8.75
FEB	3.23	1.73	6.02	7.00	4.96	-1.96	-6.38	15.99	10.87	18.17	21.37	22.17	8.75
MAR	15.49	19.97	16.69	18.55	3.26	-4.95	9.54	13.77	15.72	16.57	23.53	12.09	8.75
APR	8.31	9.82	15.24	14.50	14.63	14.12	14.52*	20.18	26.04	27.40	35.62	23.76	8.75
MAY	12.15	11.92	19.16	13.39	3.44	0.02	2.49*	8.28	13.83	17.54	24.82	12.56	8.75
JUN	13.08	7.75	16.45	13.56	3.71	1.47	3.06*	6.80	15.33	20.03	25.63	13.85	8.75
JUL	7.78	4.73	11.83	12.89	1.09	4.68	2.35*	9.18	16.87	19.68	25.02	15.30	8.75
AUG	11.51	14.28	15.67	15.34	4.97	4.70	4.92*	9.59	13.43	7.34	9.69	11.49	8.75
SEPT	9.47	-22.34	16.13	15.00	-1.67	1.84	32.45*	6.41	14.18	17.36	27.22	12.82	8.75
OCT	9.08	10.13	12.88	13.05	4.54	2.23	3.90*	10.27	16.92	16.35	22.80	15.84	8.75
NOV	12.65	12.08	20.30	10.27	4.93	0.82	3.69*	0.86	16.14	18.36	26.73	15.85	8.75
DEC	13.03	16.02	22.21	12.29	8.45	1.31	6.38*	10.82	19.32	19.98	29.28	18.31	8.75

- (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.

Note: For details on “Prior Period Amendment Effects”, see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS												
NGL REFERENCE PRICES		DECEMBER 2003										
	<i>Propane</i>	<i>Butanes</i>	<i>Pentanes</i>									
Price before amendments	194.347929	246.756484	292.719205									
Opening Rollover (from prior business mth)	-0.003705	0.002065	0.001564									
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	194.34	246.76	292.72									
TRANSPORTATION ALLOWANCES		DECEMBER 2003										
	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)	-0.003876	0.000699	0.002879	-0.001087	-0.004451	-0.000547	0.000675	-0.001591	0.001315	0.003533	0.002345	-0.000286
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)	-1.942128	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	-0.033328	0.069170	0.000000	0.000000
Total Amendment Effect	-1.946004	0.000699	0.002879	-0.001087	-0.004451	-0.000547	0.000675	-0.001591	-0.032013	0.072703	0.002345	-0.000286
Calculated Transp. Differential	14.971913	16.022471	22.205702	12.295611	8.458579	1.312986	6.376746*	10.822334	19.355772	19.907100	29.282089	18.310809
Calculated Transp. Differential after Total Amendments	13.025909	16.023170	22.208581	12.294524	8.454128	1.312439	6.377421*	10.820743	19.323759	19.979803	29.284434	18.310523
Published Transportation Allowance	13.03	16.02	22.21	12.29	8.45	1.31	6.38*	10.82	19.32	19.98	29.28	18.31

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.

**2003
ROYALTY RATES**

MONTH	METHANE-OLD (% per GJ)	METHANE-NEW (% per GJ)	ETHANE - OLD (% per GJ)	ETHANE - NEW (% per GJ)	PROPANE (% per m³)	BUTANES (% per m³)	PENTANES – OLD (POL) (% per m³)	PENTANES - NEW (PNE) (% per m³)
JAN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.41715	32.87225
FEB	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.82701	33.06254
MAR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	46.15761	33.21604
APR	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.83281	33.06523
MAY	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.25757	32.79816
JUN	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	44.82263	32.59622
JUL	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.07973	32.71559
AUG	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.19848	32.77072
SEPT	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	45.21237	32.77717
OCT	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	44.50511	32.44880
NOV	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	44.61960	32.50196
DEC	35.00000	30.00000	35.00000	30.00000	30.00000	30.00000	44.96557	32.66259

1. The Department will complete the review of reporting for Commercial Storage early in the year 2004. Amendments may have to be prepared following this review. The amendments must be completed in the Year 2004.
2. Facilities affected by 1999 volumetric filings.

AB GP 0001084	AB GP 0001695	AB GP 0001331	AB BT 0045713
AB BT 0050216	AB BT 0054967	AB BT 0059726	AB BT 0920030
AB BT 1060027	AB BT 3200090	AB BT 6360006	AB BT 8910026
AB GS 0002323	AB GS 0002326	AB GS 0002905	AB GS 0002985
AB GS 0003082	AB GS 0003135	AB GS 0003322	AB GS 0003497
AB GS 0003499	AB GS 0003767	AB GS 0004226	AB GS 0004257
AB GS 0004267	AB GS 0004532	AB GS 0004999	AB GS 0004752

3. 1999 Volumetric Discrepancies

AB BT 2690002	AB GP 0001129	AB GP 0001426	AB GS 0002485
AB BT 6010017	AB GP 0001133	AB GP 0001454	AB GS 0002562
AB GP 0001002	AB GP 0001138	AB GP 0001482	AB GS 0002612
AB GP 0001004	AB GP 0001144	AB GP 0001520	AB GS 0002783
AB GP 0001014	AB GP 0001158	AB GP 0001544	AB GS 0002813
AB GP 0001018	AB GP 0001161	AB GP 0001547	AB GS 0002821
AB GP 0001034	AB GP 0001164	AB GP 0001553	AB GS 0002952
AB GP 0001047	AB GP 0001169	AB GP 0001588	AB GS 0002995
AB GP 0001058	AB GP 0001173	AB GP 0001638	AB GS 0003151
AB GP 0001070	AB GP 0001191	AB GP 0001641	AB GS 0003640
AB GP 0001079	AB GP 0001192	AB GP 0001654	AB GS 0003919
AB GP 0001084	AB GP 0001196	AB GP 0001698	AB GS 0003973
AB GP 0001088	AB GP 0001231	AB GP 0001859	AB GS 0003981
AB GP 0001095	AB GP 0001267	AB GP 0001880	AB GS 0004153
AB GP 0001104	AB GP 0001357	AB GP 0001895	AB GS 0004156
AB GP 0001113	AB GP 0001373	AB GP 0001979	AB GS 0004267
AB GP 0001115	AB GP 0001394	AB GS 0002245	AB GS 0004383
AB GP 0001118	AB GP 0001414	AB GS 0002441	AB GS 0004581

4. Data Conversion Review

The Department has initiated an examination of the Crown royalty charges for the 1999 production year resulting from the data conversion that occurred in the September 2002 billing period invoice, to accommodate the Petroleum Registry of Alberta. The Gas Royalty Client Services staff will contact operators and owners of the affected streams to identify the potential corrections necessary to 1999 documents.

The identified streams under review are as follows:

AB WI 100012602725W400	AB WI 100073401019W400	AB WI 100143300823W400
AB WI 100012602725W402	AB WI 100080104801W400	AB WI 100143302827W400
AB WI 100012603920W403	AB WI 100081202626W400	AB WI 100143302926W402
AB WI 100012704608W400	AB WI 100081304104W502	AB WI 100143407802W600

AB WI 100013002724W400	AB WI 100083502901W500	AB WI 100152303811W400
AB WI 100020503728W400	AB WI 100090303920W400	AB WI 100153001320W403
AB WI 100021200822W400	AB WI 100093402019W403	AB WI 100153104417W403
AB WI 100021402012W400	AB WI 100100804709W400	AB WI 100160802109W400
AB WI 100021705724W402	AB WI 100100903521W400	AB WI 100160900822W400
AB WI 100022402517W400	AB WI 100101502528W400	AB WI 100161700822W400
AB WI 100023502219W400	AB WI 100102104709W400	AB WI 100162603609W402
AB WI 100030802623W402	AB WI 100102402113W400	AB WI 100163006107W400
AB WI 100032601807W400	AB WI 100111102725W400	AB WI 100163101715W400
AB WI 100040602416W402	AB WI 100111905624W400	AB WI 100163304510W402
AB WI 100041704508W400	AB WI 100112101817W400	AB WI 100163602626W400
AB WI 100042000922W400	AB WI 100112305407W400	AB WI 102042603703W500
AB WI 100042302902W500	AB WI 100113511205W602	AB WI 102043303719W400
AB WI 100042603609W400	AB WI 100120701920W400	AB WI 102061002718W400
AB WI 100050300721W400	AB WI 100120703012W400	AB WI 102061304710W400
AB WI 100053304118W400	AB WI 100122205811W400	AB WI 102061503303W500
AB WI 100053402223W400	AB WI 100130501116W400	AB WI 102080405226W402
AB WI 100053402828W400	AB WI 100130702617W402	AB WI 102110303928W400
AB WI 100061000822W402	AB WI 100130801706W402	AB WI 102123005225W400
AB WI 100061304328W402	AB WI 100131000923W400	AB WI 102140804925W400
AB WI 100061902926W400	AB WI 100132102027W400	AB WI 102162402019W402
AB WI 100061903817W400	AB WI 100140502717W400	AB WI 103012704008W400
AB WI 100062102516W400	AB WI 100140805414W400	AB WI 103140904424W400
AB WI 100062303703W500	AB WI 100141504028W402	AB WI 103160504304W500
AB WI 100062502416W400	AB WI 100141802322W400	AB WI 103160804123W400
AB WI 100062802322W400	AB WI 100141904203W502	AB WI 103161704024W400
AB WI 100070204310W500	AB WI 100142604015W400	AB WI 104062602108W400
AB WI 100072104424W402	AB WI 100143104826W400	AB WI 104102504113W402

5. 1999 AC5 Filings

Client ID	Client Name
0M9P	TH Gorkoff Investments Ltd.
0KL8	Locke Asset Management Ltd.
0PH4	River Valley Energy Services Ltd.
0KN2	Capco Resources Ltd.
0RY8	Softrock Minerals Ltd.