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Request IR-81:

Please provide copies of all agreements and contracts between any Emera entity and any Repsol entity regarding or affecting the Brunswick Pipeline, including

a. Brunswick Pipeline's tariff, as approved by the National Energy Board of Canada

b. The guarantee provided by Repsol Canada's parent company for the ship-or-pay obligation to Emera generally or Brunswick Pipeline specifically

c. Financing for the Brunswick Pipeline

d. Any other agreements involving construction, financing, or operation.

Response IR-81:

NS Power does not have access to confidential contracts relating to matters for which NS Power is not a contracting party. Documents that have been filed non-confidentially with the National Energy Board (NEB) are available in the public domain via the NEB website: http://www.neb-one.gc.ca/

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Request IR-82:

Please provide copies of all agreements and contracts between any Emera entity and any entity associated with Irving Oil regarding: (a) the Canaport liquefied natural gas (LNG) receiving facility, or (b) natural gas imported via that facility.

Response IR-82:

NS Power does not have access to confidential contracts relating to matters for which NS Power is not a contracting party. Documents that have been filed non-confidentially with the National Energy Board (NEB) are available in the public domain via the NEB website: http://www.neb-one.gc.ca/

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Request IR-83:

Please provide copies of all agreements and contracts between any Emera entity and any Repsol entity regarding: (a) the Canaport liquefied natural gas (LNG) receiving facility, or (b) natural gas imported via that facility.

Response IR-83:

NS Power does not have access to confidential contracts relating to matters to which NS Power is not a contracting party. Documents that have been filed non-confidentially with the National Energy Board (NEB) are available in the public domain via the NEB website: http://www.neb-one.gc.ca/

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Request IR-84:

Please provide copies of all agreements and contracts between any Emera entity and any entity associated with Irving Oil regarding any matter other than the Canaport liquefied natural gas (LNG) receiving facility, or natural gas imported via that facility.

Response IR-84:

NS Power does not have access to confidential contracts relating to matters to which NS Power is not a contracting party. Documents that have been filed non-confidentially with the National Energy Board (NEB) are available in the public domain via the NEB website: http://www.neb-one.gc.ca/

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Request IR-85:

Please provide copies of all agreements and contracts between any Emera entity and any Repsol entity regarding any matter other than the Canaport liquefied natural gas (LNG) receiving facility, or natural gas imported via that facility.

Response IR-85:

NS Power does not have access to confidential contracts relating to matters to which NS Power is not a contracting party. Documents that have been filed non-confidentially with the National Energy Board (NEB) are available in the public domain via the NEB website: http://www.neb-one.gc.ca/

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Request IR-86:

The forecast binders in the data room provide the solid fuel blends for 2013 and 2014 on the basis of MT quantities. Please provide similar charts for the years 2010 actual, 2011 actual and 2012 (6 months of actual and 6 months of forecast).

Response IR-86:

Please refer to Confidential Attachment 1.

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Request IR-87:

Regarding the forecast binders in the data room, please explain if the Trenton 5 maintenance schedule for 2013 is still accurate, given that this unit has had a six month forced outage in 2012. If not accurate, please provide a revised schedule.

Response IR-87:

In light of the forced outage on Trenton 5 in 2012, the outage timeline in 2013 for Trenton 5 will be adjusted and reflected in the updated fuel forecast to be filed in August as part of the established FAM and GRA processes.

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Request IR-88:

Regarding the forecast binders in the data room, please explain: (a) why charts for "Thermal Unit Capacity Deration" do not incorporate the maintenance schedules (for example the maintenance schedule shows six week outages for Lingan 3 and Trenton 5, but the Thermal Unit Capacity Deration charts do not show any derations for the referenced period of time; even though the duration schedules are based on three year averages, this still does not explain the differences), and (b) how changes in these duration schedules influence the overall forecasts of costs.

Response IR-88:

(a) Maintenance outages are included through the incorporation of the three-year average of Maintenance Outage Factor (MOF) in the development of the Fuel forecast. Please refer to OP-09 Attachment 1 page 2 of 4 of the Application. The "Thermal Unit Capacity Deration" tables are base derations for each unit that cover the typical seasonal derations. These are largely associated with changes in cooling water temperature and condenser performance though the course of the year.

(b) Changes to this schedule will affect the forecast allowing more or less capacity from a unit during the applicable month. Should the deration be increased, less capacity will be available from the unit and more energy will be required from the next unit in the dispatch order. Should the deration be decreased, more capacity will be available on that unit and less energy will be required from the next unit in the dispatch order.

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Request IR-89:

Regarding the forecast binders in the data room, please explain why the percentages in the "Solid Fuel Blends" chart do not agree with the blend percentages in the Financial Model Section, in the charts titled "Fuel Blending by Mmbtu (the charts do not relate to each other, even considering quantity versus quality differences).

Response IR-89:

The "Solid Fuel Blends" table presents fuel blends on a metric tonne basis, whereas the "Fuel Blending by Mmbtu" table presents fuel blends on an MMBtu basis. Please note that in the financial model, Power River Basin (PRB) is included in the "LS-12,000 Import %" column.

REDACTED

Request IR-90:

Regarding the forecast binders in the data room, in the Financial Model Section, on the chart related to adjustments, there are "Fuel Handling Charges" for Lingan, Aconi [redacted] per month, respectively:

a. **Please quantify these amounts, in terms of dollars, thousands of dollars, etc.**

b. **Please identify the constituents of these numbers, i.e., the categories of costs constituting these numbers,**

c. **Please explain why there are no similar costs for [redacted],**

d. **Please explain where [redacted] costs are included.**

Response IR-90:

(a) These costs are in thousands of dollars.

(b) Please refer to Confidential Attachment 1.

(c) There are no similar costs at [redacted] are included in the fuel inventory costs.

(d) As of the forecast date, NS Power is not forecasting to move coal during 2013 and 2014, to or from [redacted].

REDACTED

Request IR-91:

Regarding the forecast binders in the data room, in the solid fuel section, considering that the overall solid fuel consumption for [redacted], please explain:

a. Why the 2014 forecast would call for burning [redacted], considering [redacted] is one of the lower cost fuels available.

b. Why the 2014 consumption of [redacted], increased so dramatically, compared to 2013.

c. If the action relates to compliance with emissions regulations, please provide sufficient detail, with supporting calculations, to justify these fuel blend shifts.

d. Include analyses of trade-offs considered regarding use of mercury abatement equipment.

Response IR-91:

(a-b) Petcoke consumption is reduced in 2014 in order to stay under the environmental emissions limit for SO_2. Solid fuel consumption [redacted] in 2014 compared to 2013 due [redacted] projected natural gas prices. As a result, emissions of SO_2 [redacted] 2014.

(c) The amount of solid fuel required in 2013 and 2014 is [redacted] and [redacted], respectively. Thus in 2014, solid fuel requirements [redacted] by [redacted]. Of [redacted] tonnage, [redacted] are required at Point Aconi, and the remaining [redacted] are required at the other conventional units. The average percent sulphur in the Point Aconi blend is just over 5 percent. If the average percent sulphur in the conventional units had remained the same as in 2013 at 2.08 percent, [redacted] SO_2 emissions resulting from [redacted] solid fuel burn in 2014 can be calculated as shown below, applying the mass balance approach for percent sulphur in fuel and accounting for the 90 percent SO_2 capture of the Point Aconi fluidized bed technology:

REDACTED

[redacted]

(d) The allowable mercury emissions are 85 kg in 2013 and 65 kg in 2014. Mercury emissions in 2014 are forecast [redacted] as a result of the projected [redacted] solid fuel consumption discussed above. Thus, mercury abatement costs [redacted] in 2014 both due [redacted] mercury emissions, as well as the more restrictive mercury emission allowance. Approximately [redacted] mercury is projected to be emitted in 2014 over 2013 as a result [redacted] solid fuel consumption, for a total emission of 64.5 kg in 2014. Due to the decreased allowance in 2014 relative to 2013, higher Powder Activated Carbon (PAC) costs in the range [redacted] are

REDACTED

projected for 2014. Had blend optimization for SO_2 emissions discussed in response (c) been used to reduce Hg emissions, even more low sulphur coal than that required to reduce SO_2 emissions would be required. That is, additional low sulphur coal would be required to offset mid-sulphur coal which contains higher mercury. The additional fuel cost of using more low sulphur coal and less mid sulphur coal to reduce mercury emissions is estimated at $5.5 million. Thus, usage of PAC is more economic than consuming this higher cost blend to achieve mercury emission targets in 2014.

REDACTED

Request IR-92:

Regarding the forecast binders in the data room, given that the change in planned solid fuel consumption between 2013 and 2014 is predicted to [redacted], please explain the following:

a. Why you have forecast that the [redacted], is scheduled to experience the [redacted] in consumption.

b. Why the overall consumption of petcoke [redacted] is forecast to [redacted].

Response IR-92:

(a-b) Please refer to Liberty IR-91.

REDACTED

Request IR-93:

Regarding the forecast binders in the data room, please explain why in 2014, the consumption of PRB coal is forecast to be [redacted] (such is not true in 2013).

Response IR-93:

The chemical properties of Powder River Basin (PRB) coal are such that it has the potential to catch on fire while in storage. The risk of fire increases with time in storage. For this reason, PRBs inventory levels are actively managed. In 2013, sufficient inventory is in place to allow for maximum consumption at both Lingan and Point Aconi. PRB at Lingan is limited, for operational and risk management reasons, to an annual average in the range of [redacted]. This results in a consumption at Lingan in 2013 of [redacted]. At full load, the annual consumption of PRB at Point Aconi is limited to approximately [redacted]. Contracted and carryover amounts are such that Lingan consumption in 2014 will be limited to [redacted], the same volume as Point Aconi.

REDACTED

Request IR-94:

Please explain the differences between tonnage numbers provided in your responses to Liberty IRs 8 and 9, as follows:

Year	Quantities (MT) IR-8	Quantities (MT) IR-9
2012	[redacted]	
2014		

Response IR-94:

Information for Liberty IR-8 is sourced from the Coal Model and information for Liberty IR-9 is sourced from the fuel forecast. The fuel forecast adds auxiliary fuel at each coal plant and decreases the coal requirement. This leads to variances between actual MMBtu, and therefore metric tonnes, of coal required as per the Coal Model versus the fuel forecast.

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Request IR-95:

The response to PCC IR-2 suggests that 150 MW of coal generation will be retired by 2015 and another 150 MW by 2020. Please provide supporting information including how NSPI identified the units to be retired and their timing.

Response IR-95:

Within the data requested in PC IR-2, NS Power included a forecast of possible coal unit retirements dates within the time period requested. This forecast is the result of predicted firm peak load and planning reserve requirements and committed or anticipated firm capacity additions to the power system as outlined in Multeese IR-62. The assumed retirement dates of solid fuel unit(s) are for planning purposes. Specific units to be retired will be influenced by a variety of factors including unit and system planning considerations.

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Request IR-96:

Please describe the steps and timing of any actions NSPI is taking to arrive at a thorough and up to date resource plan; i.e., a resource plan fully reflecting the impacts of less load, cycling of some coal units, added costs from less efficient use of coal plants, lower gas prices, current understandings of GHG constraints and other factors not included in the 2009 IRP update.

Response IR-96:

There are three major outstanding initiatives which would significantly affect resource planning:

- The Pacific West Commercial Corporation (PWCC) application now before the Board.
- The NS Power initiated Renewable Energy Integration Study which is expected to be completed in 2012.
- The Muskrat Falls Hydro Electric Development and Maritime Link.

A major resource planning exercise will be undertaken when the outcomes of these activities are better known. NS Power would like the exercise to commence as soon as possible.

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Request IR-97:

Regarding the Power Production Transformation Strategy (response to Avon IR-6, Attachment 1), please provide the rationale for selecting the two unit seasonal shutdown option.

Response IR-97:

In addition to Avon IR-6, the following Information Requests provide support for the two unit seasonal operation: Please refer to Multeese IR-7, Multeese IR-62 and Avon IR-88(d-e).

Multeese IR-7 and IR-62 provide an overview of the reliability requirements that NS Power is required to meet. Given that the NewPage plant was an interruptible customer, it was not included in the calculation of Planning Reserve Margin. The loss of this load (or other non-firm load) does not reduce the system's capacity requirements. Therefore, the application of these standards will require NS Power to continue to operate its existing fleet of generating units through the peak winter months until firm load is removed from the system or additional firm capacity is added. Strategist runs were carried out for the scenarios outlined in Avon IR-6. These runs showed that, with the loss of the NewPage plant, two thermal units would not be required during non-peak load months.

Avon IR-88 and NSUARB IR-22 outline action that NS Power has taken in the short-term to realize savings as a direct result of this mode of operation. These IRs also indicate that NS Power is adopting an approach that maintains flexibility in the short-term to respond to changes in customer load while providing an opportunity for stakeholder discussions regarding the longer term plans for these units.

Request IR-98:

Regarding the Power Production Transformation Strategy (response to Avon IR-6, Attachment 1), please: (a) explain how each of the study's seven objectives (Page 5) were accomplished, and (b) provide the conclusions associated with each.

Response IR-98:

(a-b) Please refer to the list below.

1. Determine the lowest cost approach to generation dispatch

   - Alternatives were developed followed by quantitative and qualitative analysis of each. Strategist was used to develop a multi-year dispatch model. The conclusion was that:

     - In the near-term, two coal units should be operated on a seasonal basis
     - Preliminary engineering should be done to examine greater use of Power River Basin (PRB) coal usage
     - Stakeholders should be engaged in a discussion of the retirement of coal unit(s).

2. Define fuel cost ramifications for customers.

   - Fuel unit cost assumptions were updated and the Strategist multi-year model was run for each case. Changes from the Base Case fuel and purchased power expense for each year were identified.

3. Understand the directional change in asset management for the generating units to 2020.

- The Senior Manager of Asset Management and plant technical representatives reviewed the running hours for each unit that would result from the model runs. They revised the capital plans and planned outage schedules based on these results and maintenance outage expenses were reduced.

4. Define impact on the Renewable Electricity Standard (RES) Compliance Plan, the Renewable Energy Integration Study and the Emissions Compliance Plan.

- The energy requirement under each scenario was used to calculate percentage of sales and the net RES requirements for the scenarios was determined.

- The seasonal operation and retirement cases were supplied to the team studying Renewable Energy Integration. This information will be part of that study results.

- The constraints identified through the Emissions Compliance Plan were integrated into the scenarios to ensure each scenario met regulatory requirements.

5. Define impact on system operations.

- The required changes to operations with the various scenarios were determined by the Nova Scotia Power System Operator. The conclusion was that with the loss of major customers, additional resources will have to be employed to provide necessary ancillary services such as reserve.

6. Develop a range of "readiness" scenarios for the potential return to service of the NewPage plant and associated costs.

- The near-term seasonal operation of two coal units provide for the flexibility needed should the NewPage plant return to service. Lay-up costs were also estimated.

7. Define organizational impacts.

- The Human Resources team combined with Power Production Management to identify the organizational structure aligned with reduced requirements as determined by the Strategist dispatch model. The conclusion was that there was a reduction in the work force near term and plans developed for the longer term.

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Request IR-99:

Regarding the Power Production Transformation Strategy (response to Avon IR-6, Attachment 1), please: (a) provide the assumptions related to eventual unit retirements in the "momentum" strategy, and (b) if no retirements were considered in that strategy, describe whether, how, and to what extent such consideration would change the outcome.

Response IR-99:

(a) No thermal unit retirements were included in the “Momentum” strategic theme. It represents an approach where no major changes from current operations are made.

(b) The “Momentum” strategic theme was included as a base-case against which other strategies were compared.

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Request IR-100:

Regarding the Power Production Transformation Strategy (response to Avon IR-6, Attachment 1), please provide the capital investment assumptions for each plant for each year of the study.

Response IR-100:

NS Power did not break out the capital expenditures by plant as part of this study.

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Request IR-101:

Regarding the Power Production Transformation Strategy (response to Avon IR-6, Attachment 1), please provide the rationale for selecting Lingan as the units to be (a) operated seasonally and (b) retired.

Response IR-101:

The Lingan units experience the largest system losses due to their relatively longer distance from the provincial load centre. They have similar heat rates to Point Tupper and Trenton 5 and given the same fuel blend and cost over time, they are the least cost effective. Trenton 5 has a new generator while the Lingan units would require significant turbine and generator investment. The location of Trenton 5 on the mainland provides significant advantages with respect to power system efficiency and reliability, which are detailed in the response to Liberty IR-102.

Request IR-102:

Given the age and declining performance of Trenton 5, please (a) describe what consideration has been given to retiring that unit in the near future, (b) provide any analyses conducted on that topic, and (c) describe to what extent the large recent investments at Trenton 5 have precluded such considerations.

Response IR-102:

(a) Please refer to Liberty IR-101.

(b-c) There are additional factors that indicate Trenton 5 is not the best candidate for retirement.

Past capital investment, in particular a baghouse, has made Trenton 5 a more versatile unit capable of handling a broader diversity of fuel supply. Trenton 5's environmental performance with respect to mercury and particulate capture has significantly improved since the installation of the baghouse. These environmental capabilities will become increasingly important as emissions limits continue to be reduced in coming years. The 2020 emission limit for mercury is 35 kg compared to 100 kg in 2012. The Lingan units do not have baghouses. The retirement of Trenton 5 would increase the cost of the mercury capture additives required to meet the 35 kg limit relative to the cost that would result from the retirement of another unit.

In order to retire units, NS Power must demonstrate that it can continue to meet operating reserve and reliability criteria as defined by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). Specifically, the NPCC criteria require NS Power to maintain sufficient ten-minute and thirty-minute operating reserve requirements. NS Power's 18-Month Forecast and

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Assessment of System Capacity and Adequacy[1] prepared for NPCC, considers the operating reserve margin available looking ahead 18 months. The 18-Month Assessment forecasts an operating reserve margin of 13 MW in February 2013. If the loss of Bowater load is included (a firm load reduction of 29 MW) the operating reserve margin increases to 42 MW. However, with an inability to secure a firm import on the New Brunswick tie line, the retirement of a unit this winter (2012/2013) would result in a 108 MW operating reserve deficiency.

As well as meeting the NPCC operating reserve criteria, NS Power maintains a minimum planning reserve margin of 20 percent above forecasted firm peak demand in order to comply with the NPCC reliability criteria.[2] The planning reserve calculation is as follows:

> Planning Reserve Margin = (installed firm capacity – minus firm peak load) / firm peak load

Given that the NewPage and Bowater plants were primarily interruptible customers, it was not included in the calculation of planning reserve margin. Therefore, the loss of this load (or other non- firm load) does not reduce the system's capacity requirements.

While we have undertaken seasonal shut-downs of two units during off-peak months, other changes to the system are needed to allow for the retirement of a unit, while still maintaining sufficient Planning Reserve Margin. Based on the above formula, these changes would need to result in an increase in firm capacity or a reduction in firm load.

[1] http://oasis.nspower.ca/en/home/oasis/forecastsandassessments.aspx.
[2] https://www.npcc.org/Library/Resource%20Adequacy/2010_Maritimes_Area_Comprehensive_Review_of_Resource_Adequacy_RCC.pdf.

Planning Reserve Margin for 2012/2013 (winter season) is calculated at a 26 percent reserve margin with a minimal surplus of 113MW. With an inability to secure a firm import on the tie line with New Brunswick, the load and resource outlook for NS Power would indicate that the earliest a unit could be eligible for retirement is 2015.

Load and Resources Outlook for NSPI - Winter 2012/2013 to 2015/2016
Loss of Bowater firm load included
(All values in MW except as noted)

		2012/2013	**2013/2014**	**2014/2015**	**2015/2016**
A	Firm Peak Load Forecast	1,977	1,995	2,011	2,027
B	Demand Side Management (DSM) Firm	49	71	95	121
C	Firm Peak Less DSM (A - B)	1,929	1,924	1,916	1,906
D	Required Reserve (C * 20%)	386	385	383	381
E	Required Capacity (C + D)	2,314	2,309	2,299	2,287
F	Existing Resources	2412	2412	2412	2412
	Total Cumulative Additions:				
G	Thermal[1]	0	0	0	-120
H	Contracted Wind (Firm capacity)[2]	15	15	15	15
I	Biomass[3]	0	10	10	63
J	Community Feed-in-Tariff[4]	0	6	11	17
K	Total Firm Supply Resources (F + G + H + I + J)	2428	2443	2449	2388
	+ Surplus / - Deficit (K - E)	113	134	150	100
	Reserve Margin % (K-C)/C	26%	27%	28%	25%

[1] Thermal includes Burnside 4 (winter capacity 33 MW) assumed to be returned to service in 2015. Also includes assumed retirement dates of solid fuel unit(s) for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial regulations.

[2] Contracted Wind (Firm capacity) reflects the assumed firm capacity contribution based on a combined three-year average of actual capacity factor during peak hours and the annual forecasted value (as per a

formula agreed on by NS Power and the Renewable Energy Industry Association of Nova Scotia and as employed in NS Power 2009 IRP Update modeling). These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

[3] Biomass includes the PH Biomass Project and a small Independent Power Producer (IPP). The Port Hawkesbury Biomass project is currently registered for Energy Resource Interconnection Service (ERIS) but will be transitioned to firm capacity as a network resource through an application under the GIP coincident with the assumed retirement of a solid fuel unit. The assumed retirement dates of solid fuel unit(s) are for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial regulations.

[4] The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. The projects are assumed to be phased-in over 5 years starting in 2014. The value in the table is the assumed firm capacity value of intermittent generation for small-scale projects. For long-term planning purposes the firm capacity value is based on an assumed 34% capacity factor as estimated by the provincial government. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

In addition to providing planning reserve margin, generation at the Trenton facility provides flow balance among the various transmission lines connecting Cape Breton with the load centre in Halifax. With only one unit at Trenton, the flow on the 138 kV lines from Cape Breton to the mainland becomes the limiting factor across the interface known as Cape Breton Export (CBX), limiting the amount of eastern generation that can be utilized. CBX is a system interface classified by NERC as an Interconnection Reliability Operating Limit (IROL), for which limit violations can have significant adverse impact to the interconnected power system and for which limits are strictly enforced. Without Trenton Unit 5 available, the limit on CBX is reduced such that the power that would have been produced by Trenton 5 could not necessarily have been produced by generation east of Trenton, including renewable generation east of Onslow. NS Power relies on quick-start units in Cape Breton such as Wreck Cove and Victoria Junction for operating reserve and tie-line control, both of which are requirements of NERC standards and would be limited from the loss of Trenton 5.

To maintain transfer capability across the CBX without Trenton Unit 5 available, the 138 kV transmission lines from Port Hastings to Trenton would need to be uprated. The capital cost of this upgrade has been estimated to be approximately $10 million.

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Generation at Trenton provides controllable voltage support for the critical Onslow substation, as well as the Trenton and Eastern Shore areas. With Trenton Unit 5 unavailable, voltage criteria cannot be met when Trenton Unit 6 is off-line, either for maintenance or under forced outage. Supplemental reactive power sources in the form of switched capacitor banks, with an estimated cost of $1.7 million, or a Static Var Compensator, with an estimated cost of $10 million would be required.

As Trenton is physically closer to the Halifax load centre than generation units in Cape Breton, transmission loss factors are lower. This means that 150 MW delivered at Trenton is the equivalent of 156 MW delivered at Lingan. This differential would be an added cost and replaced at daily replacement energy values.

If Trenton Unit 5 was retired, Lingan Unit 1 would be required to return to active service versus its current seasonal operating mode. Seasonal operation allows for the avoidance of the planned 2016 maintenance outage. The resulting major outage would see additional capital expenditures of approximately $5 million that wouldn’t be required if Trenton 5 returned to active service.

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Request IR-103:

Figure 3-1 (DE-03 - DE-04) illustrates the accuracy of year-ahead energy forecasts. Please provide any data and analyses on the accuracy of longer term forecasts (longer term means up to five years).

Response IR-103:

Please refer to the figure below.

Annual GWh	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Forecast	**for year**	**for year**	**for year**	**for year**	**for year**	**for year**	**for year**	**for year**
Issued	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2003	12,289	12,748	12,967	13,188	13,409	13,657	13,894	14,130
2004		12,663	12,917	13,150	13,329	13,547	13,783	14,021
2005			12,850	13,077	13,272	13,475	13,690	13,890
2006				12,981	13,272	13,545	13,812	14,064
2007					12,864	13,089	13,321	13,552
2008						12,917	12,969	12,944
2009							12,444	12,402
2010								12,444
Weather-Adj.								
Actual Load	**12,334**	**12,410**	**11,175**	**12,581**	**12,551**	**12,021**	**12,310**	**12,009**
Variance %	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
Forecast	**for year**	**for year**	**for year**	**for year**	**for year**	**for year**	**for year**	**for year**
Issued	**2004**	**2005**	**2006***	**2007**	**2008**	**2009**	**2010**	**2011**
2003	**0.4%**	-2.7%	-13.9%	-4.7%	-6.7%	-12.7%	-12.7%	-17.0%
2004		**-2.0%**	-13.6%	-4.4%	-6.1%	-11.8%	-11.8%	-16.2%
2005			**-13.0%**	-3.8%	-5.6%	-11.3%	-11.1%	-15.1%
2006				**-3.1%**	-5.6%	-11.8%	-12.1%	-16.5%
2007					**-2.4%**	-8.3%	-8.1%	-12.4%
2008						**-6.9%**	-5.3%	-7.5%
2009							**-1.1%**	-3.2%
2010								**-3.5%**

*unplanned shutdown of the NewPage mill for 9 months in 2006.

The tables above show longer term load forecasts and the weather-adjusted actual annual load for those years. The year-ahead accuracy is shown in bold on the first diagonal of the variance table.

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The two-year accuracy is the second number from the left. For example, for the forecast issued in 2003, the two year variance (2005) was -2.7 percent.

It can be seen that older forecasts did not anticipate the reduction in industrial load and the move to energy conservation.

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Request IR-104:

Please describe: (a) to what extent the anticipated growth of shipbuilding activities has been included in the load forecast, and (b) the sensitivity of the load forecast to driving parameters that may be influenced by the new shipbuilding activities, such as consumer sales and housing starts.

Response IR-104:

The effects of the anticipated shipbuilding project on the Nova Scotia economy are embedded in the economic indicators used in the load forecast. NS Power has relied on the expertise of the Conference Board of Canada and Canada Mortgage and Housing Corporation to factor these effects into the appropriate variables.

Additionally, NS Power projects large industrial load based on trends and information from those firms. At this point, information from these customers suggests that large industrial increases in load related to shipbuilding will not occur during the 2013-2014 test years.

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Request IR-105:

Please provide any studies or information regarding the accuracy of Efficiency Nova Scotia Corporation forecasts of DSM savings.

Response IR-105:

NS Power has not conducted studies or surveys regarding the accuracy of the Efficiency Nova Scotia (ENSC) forecast Demand Side Management (DSM) savings. The ENSC programs have been evaluated and verified by independent consultants and their reports have been submitted to the Board.

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Request IR-106:

The RES Compliance Plan (response to Avon IR-28) indicates that Muskrat Falls via the maritime link will provide all of the additional renewable energy needed for the 2020 milestone of 25 percent renewables; please describe (a) how the NSPI capacity of the project was established, and (b) whether additional capacity is available before Gull Island.

Response IR-106:

(a) NS Power is required to achieve a target of 40 percent renewable energy by 2020. Maritime Link energy identified in the response to Avon IR-28 is the annual delivered energy as described in the project term sheet.

(b) NS Power expects Muskrat Falls energy to be available prior to Gull Island.

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Request IR-107:

With respect to OP-06, please: (a) describe how the forecasted unit heat rates were calculated, (b) provide the calculations in spreadsheet form if available, and (c) describe how, if at all, the unit performance curves are utilized in this determination.

Response IR-107:

(a) Forecasted unit heat rates were calculated according to the FAM Plan of Administration instructions which state:

> The heat rate for a unit will be calculated based on a simple average of the last three years of actual annual performance, adjusted for known capital, operating, or fuel changes or changes in the unit performance characteristics, inventory volume adjustments, and emission controls. Any adjustment will be stated in the assumptions both in magnitude and reason. The adjustment will be made to the input curve to Strategist so that the effect of dispatch on heat rate will be calculated by Strategist.[1]

(b) Please refer to Confidential Attachment 1 and note the highlighted information in yellow.

(c) Unit performance curves are supplied to Strategist as polynomial coefficients of heat input curves. The heat input curve polynomial coefficients are scaled in order for Strategist to reflect the forecasted average heat rate as described in response (a) above.

[1] FAM Plan of Administration, Appendix B, FAM Fuel Forecasting Methodology.

NON-CONFIDENTIAL

Request IR-108:

Please explain the assumptions, and their bases, underlying the determination of the portion of installed wind capacity that is considered firm.

Response IR-108:

Please refer to CA IR-96.

NON-CONFIDENTIAL

Request IR-109:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, security for NewPage Port Hawkesbury's (NPPH's) performance under its contracts with NSPI was provided by NPPH between the contract execution date and the commercial operations date by a $220,000 per month performance deposit, total not to exceed $6 million, and a limited guarantee from a parent company of up to $15 million. (See Nova Scotia Utility and Review Board, In the Matter of the Public Utilities Act and In the Matter of an Application by Nova Scotia Power Incorporated for approval of capital work order CI# 39029, Port Hawkesbury Biomass Project, at a cost of $208.6 million, Docket No. NSUARB-P-128.10, Decision 2010 NSUARB 196, dated October 14, 2010, at page 9.)

a. What funds were received by NSPI under this provision?

b. How did NSPI account for those funds?

Response IR-109:

(a) Since 2010, NS Power had received ten performance deposit installments of $220,000 from NewPage Port Hawkesbury totalling $2,200,000. The last instalment was received on September 6, 2011. NS Power has not received any funds pursuant to the limited guarantee.

(b) The performance deposit funds are accounted for as a short term liability for the purposes of financial reporting.

NON-CONFIDENTIAL

Request IR-110:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, in its reply evidence in the capital work order proceeding (NSUARB-P-128.10), NSPI argued that a number of provisions leave risk with NPPH, including

a. Providing step-in rights in the EPC and MOMA contracts in the event that NPPH has defaulted on its obligations

b. A performance deposit for the life of the project.

(Cited in October 14, 2010, Decision 2010 NSUARB 196 in NSUARB-P-128.10, at p. 10.)

Please describe what happened under these provisions when NPPH entered bankruptcy.

Response IR-110:

(a) NS Power facilitated an orderly transition of the biomass construction project upon NewPage Port Hawkesbury Corp. (NPPH) applying for protection from creditors pursuant to the Companies' Creditors Arrangement Act (CCAA).

(b) The performance deposit continues to be held by NS Power pending final resolution of the CCAA process.

NON-CONFIDENTIAL

Request IR-111:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, please explain in detail what happens to the electrical output from the biomass plant when the paper mill is no longer using steam from the boiler.

Response IR-111:

In the case where the mill is no longer using steam from NS Power's boiler, that steam can be used to generate Renewable Electricity Standard (RES) compliant electricity for delivery into the transmission system.

CONFIDENTIAL (Attachment Only)

Request IR-112:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, the Shaw Group's Evidence in the capital work order proceeding for the Port Hawkesbury biomass plant (Exhibit N-2, Appendix 10, pp. 61-62) recommended that Design Criteria documents be developed. Please provide a copy of those documents.

Response IR-112:

Please refer to Confidential Attachments 1-5.

NON-CONFIDENTIAL

Request IR-113:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, please describe the Shaw Group's involvement in the final design and construction phases of the Port Hawkesbury biomass plant.

Response IR-113:

The Shaw Group has been retained as a consultant to NS Power and is utilized on an as needed basis to review certain engineering documents such as pipe stress analysis in order to provide a second expert opinion. Through the construction phase, the Shaw Group is consulted on technical issues and good utility construction practice, again on an as needed basis.

CONFIDENTIAL (Attachment Only)

Request IR-114:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, the Company's Application for approval of the capital work order contained a breakdown of the $208.6 million project cost that was reproduced on page 25 of the Board's order approving the project (Decision in NSUARB-P-128.10, 2010 NSUARB 196). Please provide a current estimate of the project's costs, divided into the same categories.

Response IR-114:

Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-115:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, the Board's order approving the project (Decision in NSUARB-P-128.10, 2010 NSUARB 196) required that, "Should the contract price escalate as a consequence of the filing of this decision after October 1, 2010, NSPI will not be entitled to pass the contract escalation on to ratepayers and must absorb it as a shareholder cost." Order at p. 38.

a. Did the contract price escalate as a consequence of filing the decision after October 1, 2010?

b. If so, how were the extra costs recorded in NSPI's books of account?

Response IR-115:

(a-b) No.

NON-CONFIDENTIAL

Request IR-116:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, pages 62-63, the Board's order approving the project (Decision in NSUARB-P-128.10, 2010 NSUARB 196) noted that, "The Board does acknowledge that on closing NSPI will receive a letter of credit in the amount of $10 million in addition to parental guarantees securing performance of the EPD Agreement and MOMA." (Order at p. 48) Please describe

a. Whether the letter of credit and parental guarantees were indeed received?

b. What has happened with respect to those assurances as a result of NewPage's reorganization?

Response IR-116:

(a) The letter of credit was received. Of note is that the Letter of Credit is actually $15,000,000 USD. This increase is pursuant to Section 36.1(b) of the Engineering, Procurement and Construction (EPC) Contract providing that the amount of the Letter of Credit was to be increased from $10 million to $15 million on the earlier of (a) the date on which the total contract price invoiced met or exceeded $10 million or (b) January 7, 2011. Prior to January 7, 2011, NewPage Port Hawkesbury (NPPH) delivered an amendment to the Letter of Credit increasing its amount to $15 million.

(b) The Letter of Credit was held by NS Power as security under the EPC Agreement and, in NS Power's view, the security of the Letter of Credit was not impacted by NewPage's Companies' Creditors Arrangement Act (CCAA) proceedings. On April 25, 2012 NS Power drew down the complete $15,000,000 USD ($14,710,500 CAD) Letter of Credit based on NS Power's damages incurred to date and its reasonable estimate of further damages pursuant to NewPage's defaults under the EPC Contract.

NON-CONFIDENTIAL

NS Power continues to hold the guarantees, which were provided by NewPage Corporation. Shortly before NPPH filed for protection pursuant to the CCAA, NewPage Corporation filed for Chapter 11 in the United States. Based on careful consideration (including consideration of other collateral) and consultation with Canadian and U.S. insolvency experts, NS Power determined that the potential benefits (if any) of submitting a proof of claim in the Chapter 11 proceedings of NewPage Corporation for the claim under the guarantees were outweighed by the potential costs/risks of being drawn into the Chapter 11 proceedings.

NON-CONFIDENTIAL

Request IR-117:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04, Appendix B, page 11, lines 9-12,

a. Does the Company expect that the availability of power from the Brooklyn Power Project will be affected by Resolute Forest Products Inc.'s decision to stop production and sell the assets of the Bowater Mersey plant in Liverpool?

b. What effects does the Company expect?

Response IR-117:

Please refer to NSUARB IR-51(e).

REDACTED

Request IR-118:

Regarding NS Power 2013 General Rate Application, Section 1, DE-03 – DE-04 Appendix B, page 8,

a. Please describe the sources of biomass for the biomass plant, with the estimated annual quantities available from each source

b. Please describe quantitatively how the estimated cost of each source compares with the costs of each in the Company's Application in NSUARB-P-128.10.

Response IR-118:

(a) A procurement plan for biomass is under development, which will provide estimated quantities from various sources.

(b) The price estimate in the Application assumed [redacted] and used the same price as that submitted for harvested sources in the Biomass Application.[1]

[1] NSPI Port Hawkesbury Biomass Project CI 39029, Capital Work Order Application, NSUARB-NSPI-P-128-10, April 9, 2010.

REDACTED

Request IR-119:

Regarding the Company's response to 2013 GRA Avon IR-69, Attachment 1, p. 2, please explain why production from Minas Basin Pulp and Paper is forecast to [redacted]

Response IR-119:

Information for 2012 is based on the 2012 GRA test year forecast, as of December 31, 2010. At that time, Minas Basin Pulp and Power was forecasted to begin producing power in [redacted]. The information for the 2013 and 2014 test year forecasts, as of December 31, 2011, assume Minas Basin Pulp and Power will [redacted].

CONFIDENTIAL (Attachment Only)

Request IR-120:

With respect to the Company's response to Liberty IR-13 in this proceeding, the Company reports that it subscribes to the following services related to natural gas forecasting: PIRA Energy Group North American Natural Gas Retainer Service, PIRA Energy Group Scenario Planning Service and Energy Ventures Analysis, Inc. Fuelcast Long-Term Outlook. Please provide what each of these services forecasts for 2013 and 2014 for the following:

a. Monthly wholesale natural gas prices for delivery points on the Canadian segment of the Maritimes & Northeast Pipeline system

b. Monthly direction and quantities of flows on the Canadian segment of the Maritimes & Northeast Pipeline system

c. Monthly direction and quantities of flows on the U. S. segment of the Maritimes & Northeast Pipeline system

d. Deliveries of liquefied natural gas to the Canaport LNG receiving terminal

e. The per-MMBtu landed price for LNG delivered to the vicinity of Canaport in each calendar quarter of 2013 and 2014.

Response IR-120:

(a-d) None of the referenced subscriptions publish the information requested.

(e) Please refer to Confidential Attachment 1 for forecast pricing for Liquefied Natural Gas (LNG) for the Atlantic and Pacific basins. As LNG is a globally traded commodity, the attached data is NS Power's best indicator of the forecasted range in pricing for LNG delivered to the vicinity of Canaport.

NON-CONFIDENTIAL

Request IR-121:

With respect to the Company's response to Liberty IR-24 in this proceeding, please provide

a. Maritimes gas production and consumption data through the latest date available. Please segregate production data by source; i.e., McCully Field, SOEP, etc.

b. The Company's best estimates of Maritimes gas production in each of the months of 2013 and 2014. Again, please segregate production estimates by source

c. The Company's best estimate of the beginning of production from EnCana's Deep Panuke Field, and of monthly production thereafter.

Response IR-121:

(a) Please refer to Attachment 1. There is no data available for consumption.

(b-c) Please refer to Attachments 2 and 3.

National Energy Board Office national de l'énergie

Marketable Natural Gas Production in Canada
Production de gaz naturel commercialisable au Canada

Marketable Production (10^3m^3/d) / Production de gaz commercialisable (10^3m^3/j)								
2011	**Nova Scotia Nouvelle-Écosse**	**New Brunswick Nouveau-Brunswick**	**Ontario**	**Saskatchewan**	**Alberta**	**British Columbia Colombie-Britannique**	**NWT & Yukon T.N.-O. et Yukon**	**Canada Total Total au Canada**
January / Janvier	7,360	504	435	13,259	292,696	90,624	570	405,448
February / Février	8,045	493	432	13,108	294,868	91,047	561	408,554
March / Mars	8,011	478	403	13,232	293,323	94,088	516	410,052
April / Avril	7,833	473	413	12,993	303,434	99,535	605	425,286
May / Mai	7,752	419	439	12,849	292,000	100,155	477	414,090
June / Juin	4,841	471	450	12,699	293,261	89,494	409	401,624
July / Juillet	7,355	434	442	12,738	295,266	97,850	399	414,484
August / Août	7,462	427	419	12,936	290,671	99,529	400	411,844
September / Septembre	7,143	426	450	13,006	291,705	98,344	442	411,515
October / Octobre	6,633	415	442	13,140	287,401	102,571	578	411,179
November / Novembre	6,585	406	427	13,049	295,170	101,491	594	417,723
December / Décembre	7,048	398	429	13,120	299,314	104,117	583	425,009

Source: Public information from reporting agencies and the NEB
Figures in blue print are NEB projected estimates of production from the May 12, 2011 report: *"Short-term Canadian Natural Gas Deliverability 2011 - 2013"*
NWT = North West Territories
Notes: (1) Marketable production for the NWT and Yukon are calculated using NEB shrinkage estimates and raw production data publicly available at
http://www.stats.gov.nt.ca/Statinfo/industry/non_renew/production.otp for the NWT and
http://www.emr.gov.yk.ca/oilandgas/exploration.html#rig for the Yukon.
(2) British Columbia marketable production is derived from raw gas produced in British Columbia, and does not include raw gas from the NWT or Yukon.
Canada Total is sum of actual and projected values in the table by month

Source : Renseignements du domaine public provenant des organismes faisant rapport et de l'ONÉ
Les données en bleu représentent les prévisions estimatives de l'ONÉ à l'égard de la production et sont extraites de son rapport du 12 Mai 2011
intitulé *"Productibilité à court terme de gaz naturel au Canada 2011-2013"*
T.N.-O. = Territoires du Nord-Ouest
Notes : 1) La production de gaz commercialisable des T.N.-O. et du Yukon est calculée à partir des estimations de contraction faites par l'ONÉ et des données de production brute consultables ici :
http://www.stats.gov.nt.ca/Statinfo/industry/non_renew/production.otp pour les T.N.-O. et
http://www.emr.gov.yk.ca/oilandgas/exploration.html#rig pour le Yukon.
2) La production de gaz commercialisable de la Colombie-Britannique est dérivée du gaz brut produit en Colombie-Britannique et ne comprend pas celui qui provient des T.N.-O. ou du Yukon.
Les chiffres dans la colonne Total au Canada constituent le cumul des données réelles et des prévisions estimatives pour chaque mois.

Canada

National Energy Board Office national de l'énergie

Marketable Natural Gas Production in Canada
Production de gaz naturel commercialisable au Canada

Marketable Production ($10^3m^3/d$) / Production de gaz commercialisable ($10^3m^3/j$)								
2012	**Nova Scotia Nouvelle-Écosse**	**New Brunswick Nouveau-Brunswick**	**Ontario**	**Saskatchewan**	**Alberta**	**British Columbia Colombie-Britannique**	**NWT & Yukon T.N.-O. et Yukon**	**Canada Total Total au Canada**
January / Janvier	6,974	618	441	12,869	290,126	106,509	566	418,103
February / Février	6,435	528	439	12,360	298,561	106,639	580	425,541
March / Mars	6,939	600	437	12,248	285,988	108,089	440	414,741
April / Avril	4,176	557	435	12,133	284,665	109,861	435	412,263
May / Mai	7,383	534	433	12,020	282,269	109,944	431	413,015
June / Juin	8,529	533	432	11,910	279,786	109,226	426	410,841
July / Juillet	9,675	498	430	11,807	277,703	108,483	421	409,016
August / Août	10,821	482	428	11,710	275,952	108,188	416	407,996
September / Septembre	11,967	343	426	11,617	274,218	107,989	411	406,971
October / Octobre	13,113	459	424	11,534	272,646	107,683	406	406,265
November / Novembre	12,988	445	423	11,455	271,284	107,551	401	404,547
December / Décembre	12,864	431	421	11,369	270,101	107,701	397	403,283

Source: Public information from reporting agencies and the NEB
Figures in blue print are NEB Mid-range case projected estimates of production from the April 19, 2012 report: *"Short-term Canadian Natural Gas Deliverability 2012 - 2014"*
NWT = North West Territories
Notes: (1) Marketable production for the NWT and Yukon are calculated using NEB shrinkage estimates and raw production data publicly available at
http://www.stats.gov.nt.ca/Statinfo/industry/non_renew/production.otp for the NWT and
http://www.emr.gov.yk.ca/oilandgas/exploration.html#rig for the Yukon.
(2) British Columbia marketable production is derived from raw gas produced in British Columbia, and does not include raw gas from the NWT or Yukon.
Canada Total is sum of actual and projected values in the table by month

Source : Renseignements du domaine public provenant des organismes faisant rapport et de l'ONÉ
Les données en bleu représentent les prévisions estimatives de l'ONÉ à l'égard de la production et sont extraites de son rapport du 19 Avril 2012
intitulé *"Productibilité à court terme de gaz naturel au Canada 2012-2014"*
T.N.-O. = Territoires du Nord-Ouest
Notes : 1) La production de gaz commercialisable des T.N.-O. et du Yukon est calculée à partir des estimations de contraction faites par l'ONÉ et des données de production brute consultables ici :
http://www.stats.gov.nt.ca/Statinfo/industry/non_renew/production.otp pour les T.N.-O. et
http://www.emr.gov.yk.ca/oilandgas/exploration.html#rig pour le Yukon.
2) La production de gaz commercialisable de la Colombie-Britannique est dérivée du gaz brut produit en Colombie-Britannique et ne comprend pas celui qui provient des T.N.-O. ou du Yukon.
Les chiffres dans la colonne Total au Canada constituent le cumul des données réelles et des prévisions estimatives pour chaque mois.

Canada

National Energy Board

Office national de l'énergie

Short-term Canadian Natural Gas Deliverability

2012-2014

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gas

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NE2-1/2012E-PDF
ISSN: 1910-7773

This report is published separately in both official languages. This publication is available upon request in multiple formats.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
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1-800-899-1265
Internet: www.neb-one.gc.ca

For pick up at the NEB office:
Library
Ground Floor

Printed in Canada

NE2-1/2012F-PDF
ISSN: 1910-779X

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
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Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

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Acronyms

CAODC	Canadian Association of Oilwell Drilling Contractors
CBM	coalbed methane
EIA	Energy Information Administration
EMA	Energy Market Assessment
HH	Henry Hub (U.S. Natural Gas Reference Price)
LNG	liquefied natural gas
NEB	National Energy Board
NGLs	natural gas liquids
NIT	Nova Inventory Transfer
PSAC	Petroleum Services Association of Canada
WCSB	Western Canada Sedimentary Basin

Units

m^3	= cubic metres
MMcf	= million cubic feet
Bcf	= billion cubic feet
m^3/d	= cubic metres per day
$10^6 m^3/d$	= million cubic metres per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day
GJ	= gigajoule
MMBtu	= million British Thermal Units

Common Natural Gas Conversion Factors

1 million m^3 (@ 101.325 kPaa and 15° C) = 35.3 MMcf (@ 14.73 psia and 60° F)
1 GJ (Gigajoule) = .95 Mcf (thousand cubic feet) = .95 MMBtu = .95 decatherms

Price Notation

North American natural gas prices are quoted at Henry Hub and given in $US/MMBtu.
Canadian natural gas prices are quoted as the Alberta Gas Reference Price and are listed in $C/GJ.

Foreword

The National Energy Board (the NEB or the Board) is an independent federal regulator whose purpose is to promote safety and security, environmental protection and efficient infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament for the regulation of pipelines, energy development, and trade.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and natural gas pipelines, international power lines, and designated interprovincial power lines. Furthermore, the Board regulates the tolls and tariffs for the pipelines under its jurisdiction. With respect to the specific energy commodities, the Board regulates the export of natural gas, oil, natural gas liquids (NGLs) and electricity, and the import of natural gas. Additionally, the Board regulates oil and natural gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements.

The Board also monitors energy markets, and provides its view of the reasonable foreseeable requirements for energy use in Canada having regard to trends in the discovery of oil and natural gas[2]. The Board periodically publishes assessments of Canadian energy supply, demand and markets in support of its ongoing market monitoring. These assessments address various aspects of energy markets in Canada. This Energy Market Assessment (EMA), *Short-term Canadian Natural Gas Deliverability, 2012–2014*, is one such assessment. It examines the factors that affect natural gas supply in Canada in the short term and presents an outlook for deliverability through 2014.

While preparing this report, in addition to conducting its own quantitative analysis, the NEB held a series of informal meetings and discussions with natural gas producers, pipeline companies, and industry associations. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social considerations that change as society's values and preferences evolve over time.

2 This activity is undertaken pursuant to the Board's responsibilities under Part VI of the *National Energy Board Act* and the Board's decision in GHR-1-87.

C H A P T E R O N E

Overview and Summary

This report provides an outlook for Canadian natural gas deliverability[3] from the beginning of 2012 to the end of 2014.

Major factors influencing deliverability over this period include:

- Canadian natural gas prices generally increased from 2003 to 2008, averaging almost $7.00/GJ. Prices have since declined and the Nova Inventory Transfer (NIT) price averaged $3.28/GJ in 2011. The decline in prices is due to oversupply conditions caused by rising U.S. shale gas production during a time of slowing demand growth. Recent oil prices are much greater than the price of natural gas on an energy equivalency basis. The price differential between oil and gas continues to draw investment to oil and away from natural gas.
- The divergence between natural gas and oil prices is altering the economics of natural gas produced in the presence of noticeable amounts of natural gas liquids (NGLs) compared to those without (dry natural gas).[4]
- Dry natural gas targeted drilling is not economic at current natural gas prices. At current prices, the revenues earned by natural gas sales over a well's producing life are not likely to cover the costs to find, develop, and produce the gas including a reasonable return on the investment.
- Liquids-rich or wet natural gas targeted drilling can be economic at current natural gas and oil prices. Extraction and sale of NGLs from the gas stream supplements the revenue earned from producing natural gas. Depending on the amount of NGLs in the natural gas, the additional revenue earned from the sale of the NGLs can be more than the revenue earned from the natural gas itself. NGL prices tend to more closely follow the price of oil.

These important factors have diverted investment and drilling activity away from targeting dry natural gas in Canada and the U.S., and will likely cause Canadian deliverability to decline over the projection period. Total Canadian natural gas deliverability will continue to be well above the level of Canadian demand.

Recognizing the uncertainty associated with future natural gas prices, this report examines three price cases for Canadian natural gas deliverability.

3 Deliverability is the estimated amount of gas supply from a given area based on historical production and individual well declines, as well as projected activity. Gas production may be less than deliverability due to a number of factors, such as weather related supply interruptions, and shut-in production due to economic or strategic considerations.

4 NGLs are liquid hydrocarbons including propane, butanes, and pentanes plus. Natural gas containing commercial amounts of NGLs is known as NGL-rich, liquids-rich or wet gas. Dry natural gas contains little or no NGLs. Gas produced from oil wells includes gas in solution within the oil (solution gas) and gas adjacent to the oil within the reservoir (associated gas). Production of solution gas and associated gas is almost entirely dictated by oil operations, and is typically not influenced by natural gas market conditions.

- A Lower Price Case based upon persistent oversupply conditions where natural gas prices remain below 2011 levels throughout the projection period. Prices reach $3.00/MMBtu in 2014. New natural gas drilling predominantly targets liquids-rich natural gas. Deliverability declines steadily from 400 $10^6 m^3/d$ (14.1 Bcf/d) in 2012 to 341 $10^6 m^3/d$ (12.0 Bcf/d) in 2014.
- A Higher Price Case where current oversupply conditions end by 2014, causing natural gas prices to reach $6.00/MMBtu. At this point, drilling for dry gas in Western Canada becomes economic. A return to dry gas drilling in 2014 would only begin to impact deliverability later in the projection period. As a result, deliverability would continue to decline, but to a lesser extent reaching 403 $10^6 m^3/d$ (14.2 Bcf/d) in 2013 and 385 $10^6 m^3/d$ (13.6) Bcf/d in 2014.
- A Mid-Range Price Case resulting from a reduction in oversupply conditions that leads to a $4.50/MMBtu natural gas price by 2014. Prices support drilling for NGL-rich gas and minor levels of dry gas drilling. Deliverability trends downward to 373 $10^6 m^3/d$ (13.2 Bcf/d) by 2014.

The Analysis and Outlook section of this report contains the key assumptions for each price case.

The Appendices contains a detailed description of the methodology used in projecting deliverability.

BACKGROUND

The Canadian and U.S. natural gas supply has been affected by recent growth in natural gas production. Highlighted below are key factors that have shaped expectations regarding future deliverability.

General

- Canadian and U.S. natural gas prices have declined and are near their lowest levels in almost a decade due to growing U.S. deliverability and a slowing of demand growth. In contrast, oil prices have increased and are nearing their highest average annual level in over a decade.
- Total Canadian and U.S. marketable (sales) natural gas[5] production has increased since 2005 and is currently at approximately 2153 $10^6 m^3/d$ (76 Bcf/d). The growth of natural gas production can mostly be attributed to an increase in shale gas activity in the U.S.

Canada

- Western Canada is the major source of domestic natural gas production and currently accounts for approximately 98 per cent of total Canadian marketable production. Nova Scotia and New Brunswick[6] provide most of the remaining natural gas production with minor amounts coming from Ontario, Northwest Territories, and Yukon.
- In 2011, Canada produced approximately 414 $10^6 m^3/d$ (14.6 Bcf/d) of natural gas - a slight increase over 2010. Canadian natural gas production had previously declined from 482 $10^6 m^3/d$ (17.0 Bcf/d) in 2005 to 431 $10^6 m^3/d$ (15.2 Bcf/d) by late 2009.
- Until 2006, natural gas had consistently been the target of 70 to 80 per cent of the oil and gas wells drilled in Canada. Since 2006, gas targeted drilling has declined steadily, and in 2011 accounted for only 37 per cent of drilling.
- Canada's deliverability continues to exceed its own demand needs and the remaining production is exported to the U.S.

5 Marketable (sales) gas is gas that has been processed to remove impurities and NGLs, and meets specifications for use as an industrial, commercial, or domestic fuel.

6 The Canaport terminal in New Brunswick is the only operating liquefied natural gas (LNG) import terminal in Canada. Since gas supply for LNG projects comes from outside the country, LNG imports are not included in this report on Canadian gas deliverability.

U.S.

- U.S. natural gas production occurs in many of the lower-48 states and offshore in the Gulf of Mexico. Alaskan production does not have access to markets in Canada or the lower-48 states.
- The U.S. averaged 1720 10^6m^3/d (60.7 Bcf/d) of natural gas production in 2011. The increase in shale gas production from the Gulf Coast, Mid-Continent, and Northeast regions currently exceeds the growth in natural gas demand in all of Canada and U.S., contributing to the oversupply situation in North America. The increasing U.S. deliverability is accommodating more of that country's requirements and reducing the need for imports from Canada.
- Natural gas targeted drilling in the U.S. has followed the same decreasing trend as in Canada as activity has shifted to oil, and currently sits at approximately 45 per cent of the total oil and gas wells drilled in a year.

KEY DRIVERS OF DELIVERABILITY

Key supply and demand drivers influencing future Canadian natural gas deliverability include:

- Natural gas producers in Canada responding to the decline in prices by shifting drilling activity away from dry natural gas to liquids-rich natural gas and crude oil projects.
    - Producers will continue to target natural gas deposits that are richer in liquid hydrocarbons (propane, butanes, and pentanes plus) since those liquids provide an additional source of revenue. However, liquids-rich/wet natural gas wells often produce less gas than dry natural gas wells.
    - Horizontal drilling and multi-stage hydraulic fracturing[7] techniques originally employed in shale gas developments have migrated into crude oil recovery. Many formations previously considered too impermeable to produce economic quantities of oil are now the target of drilling. These new oil targets are attracting significant upstream investment.
    - The additional crude oil and bitumen drilling will increase utilization of labour, materials, and equipment and could contribute to cost inflation in the drilling and service industries. Cost inflation will be felt in service industry activity and add to the competitive environment for producers targeting natural gas or oil.
- Canadian producers are continuing to drill a greater percentage of gas wells that target deeper formations in British Columbia and western Alberta. Deeper formations often produce at higher rates, but are more costly to develop.
    - Additional higher capacity drilling rigs are being constructed to drill into medium and deep formations with long horizontal legs. Rigs that target shallow formations will remain heavily under-utilized.
    - The growing use of high-horsepower drilling rigs is increasing the efficiency of deeper drilling operations.
    - The decline in gas prices has made it difficult to raise investment capital for shallow gas drilling and has significantly reduced shallow gas activity in Saskatchewan and southeastern Alberta.
- Production can occur from multiple formations simultaneously, thereby increasing the potential productivity of new wells.
- Levels of natural gas drilling in Canada over the 2012 to 2014 period will likely not be adequate to offset ongoing declines in output from existing producing wells. Even though new wells are producing natural gas at higher initial rates, overall deliverability is likely to decrease.

7 Fracturing is a technique in which fluids are injected underground, in multiple stages, to create or expand existing fractures in the rock, allowing oil or gas to flow out of the formation, or to flow at a faster rate.

- The combination of lower natural gas prices and higher oil prices has led to a pullback in natural gas drilling in B.C.'s Horn River Basin. Even though individual wells from the Horn River Basin produce gas in large quantities, the natural gas is dry.
  - Most producers that restrained their Horn River Basin drilling operations in 2011 appear to be keeping drilling activity at a lower level until market conditions improve.
  - Horn River Basin producers that have agreements with joint venture partners to contribute capital towards drilling and completion costs may maintain or increase activity over the 2012 to 2014 period.
- Declining natural gas production prior to 2010 and increased gas consumption in the oil sands have reduced the utilization of pipelines leaving Western Canada. As utilization drops, unit transportation costs tend to rise. This affects the competitiveness of Western Canadian gas in markets in Central Canada, as well as markets in the U.S.
- LNG net imports into Canada and the U.S. stabilized at approximately 31.2 $10^6m^3/d$ (1.1 Bcf/d) through most of 2011. This level represents approximately six per cent of Canada and U.S. import capacity. LNG imports are unlikely to increase as long as oversupply conditions in Canada and the U.S. keep prices below European and Asia-Pacific markets.
- LNG exports from Canada have the potential to begin in the next few years. The minor volume of natural gas proposed for export in 2015 is not likely to influence Canadian natural gas prices.
- A moderating factor on any potential increase in Canadian and U.S. natural gas prices is the prospect of additional U.S. natural gas supplies entering the market. These include an inventory of highly productive U.S. shale gas wells that are not yet completed or connected into the pipeline system. While producers may postpone the production of newly drilled wells in the current price environment, eventually these wells will add to overall natural gas production. It is possible that the oversupply of natural gas in North America could extend through 2014.
- Participants in natural gas markets are able to reduce the risk of price volatility by locking in the price of a future delivery of natural gas. Since prices began declining in 2009, this form of contracting a future natural gas price, or "hedging", has allowed producers to capture prices higher than the current spot price. Through this practice, the gas sales revenues to hedged producers may reflect a higher average price for the year than indicated by the standard market indexes (Henry Hub in the U.S., NIT in Western Canada). Producers were able to base their natural gas drilling activities on the higher price that they achieved through hedging. As producers look out to 2013 and beyond, futures prices have tended to be lower than the cost to supply the gas, and this means a hedge would be equivalent to locking in a guaranteed loss on a future sale. Understandably, producers have been pulling back from applying new hedges in the current pricing environment. Indications are that much less natural gas has been or will be hedged in 2013 and 2014 and that market index prices will be more reflective of actual sales prices for those years.
- Natural gas-fired power generation is competing with some of the older and less-efficient coal-fired units in some markets. This occurs when natural gas prices decline to levels where gas generation is cost-competitive with coal. This increases gas demand and could gradually reduce the oversupply situation.
- Expanding oil sands production is also increasing natural gas demand in Western Canada.

ANALYSIS AND OUTLOOK

A decline in natural gas drilling activity is expected over the projection period in the Mid-Range and Lower Price Cases. The Higher Price Case will see a decline in drilling activity before increasing in 2014. As natural gas drilling activity slows while Canadian and U.S. demand increases, natural gas prices may begin to trend upward, eventually providing the incentive for additional natural gas drilling. The timing and degree of this transition from declining to increasing natural gas activity is uncertain. To help address the uncertainty, this report examines three price cases for Canadian natural gas deliverability. These cases differ primarily in terms of Canadian and U.S. natural gas prices and the corresponding levels of capital investment. The cases also vary in terms of drilling levels targeting wet gas and dry gas, particularly in the Montney play of Alberta and B.C., and Horn River Shale prospects in northeastern B.C. The Appendices contain a detailed description of the methodology used for projecting deliverability. The cases are:

- A Lower Price Case based upon persistent oversupply conditions where natural gas prices remain below 2011 levels throughout the projection period. Prices reach \$3.00/MMBtu in 2014. New natural gas drilling predominantly targets liquids-rich natural. Deliverability declines steadily from 400 $10^6m^3/d$ (14.1 Bcf/d) in 2012 to 341 $10^6m^3/d$ (12.0 Bcf/d) in 2014.
- A Higher Price Case where current oversupply conditions end by 2014, causing natural gas prices to reach \$6.00/MMBtu. At this point, drilling for dry gas in Western Canada becomes economic. A return to dry gas drilling in 2014 would only begin to impact deliverability later in the projection period. As a result, deliverability would continue to decline, but to a lesser extent reaching 403 $10^6m^3/d$ (14.2 Bcf/d) in 2013 and 385 $10^6m^3/d$ (13.6 Bcf/d) in 2014.
- A Mid-Range Price Case resulting from a reduction in oversupply conditions that leads to a \$4.50/MMBtu natural gas price by 2014. Prices support drilling for NGL-rich gas and minor levels of dry gas drilling. Deliverability trends downward to 373 $10^6m^3/d$ (13.2 Bcf/d) by 2014.

A summary of the key assumptions used in the cases and the deliverability results is shown in Table 4.1:

TABLE 4.1

Pricing Overview and Deliverability Results

		Mid-Range Price Case			Higher Price Case			Lower Price Case		
	2011	2012	2013	2014	2012	2013	2014	2012	2013	2014
Henry Hub (HH) Average Price (US$/ MMBtu)	$4.00[1]	$3.75	$4.25	$4.50	$4.75	$5.25	$6.00	$2.50	$2.75	$3.00
Alberta Gas Reference Price (C$/ GJ)	$3.28[2]	$3.11	$3.51	$3.69	$4.12	$4.53	$5.22	$1.86	$1.98	$2.15
Natural Gas Drilling Expenditures ($ Millions)		6362	6159	5455	6967	6530	7276	3622	3160	2838
Natural Gas-Intent Drill Days		32714	30482	26470	34889	31187	33655	19120	16030	14108
Natural Gas-Intent Wells Drilled	2782[3]	2159	1755	1384	2297	1761	2118	887	637	533
Gas Share of Drill Days (per cent)	37	30	25	20	32	30	33	25	23	18
Size of WCSB Rig Fleet	795[4]	803	799	796	812	808	804	789	785	782
Canadian Deliverability (10^6m^3/d)	**414[5]**	**410**	**397**	**373**	**413**	**403**	**385**	**400**	**372**	**341**
Canadian Deliverability (Bcf/d)	**14.6**	**14.5**	**14.0**	**13.2**	**14.6**	**14.2**	**13.6**	**14.1**	**13.1**	**12.0**

1 EIA– Short Term Energy Outlook, 10 Jan 2012. http://www.eia.gov/forecasts/steo/data.cfm

2 Government of Alberta, Alberta Gas Reference Price History - January - December 2011, http://www.energy.alberta.ca/NaturalGas/1322.asp

3 PSAC Estimate – 26 January 2012.

4 CAODC Estimate – 27 January 2012.

5 Annual average of NEB reported provincial production, where available.

For this analysis, the Board divides natural gas production in Western Canada into conventional, coalbed methane (CBM), and shale gas categories. Within the conventional gas category, there is a sub-category called tight gas. Due to large regional differences in physical and producing characteristics, the Board further subdivides these categories into smaller geographic areas, or regions, which have similar characteristics for production decline analysis. Within each region, grouping of the producing formations takes place on a geological basis. Details on the characterization of the resources are available in Appendix B. Canadian natural gas production outside of Western Canada includes:

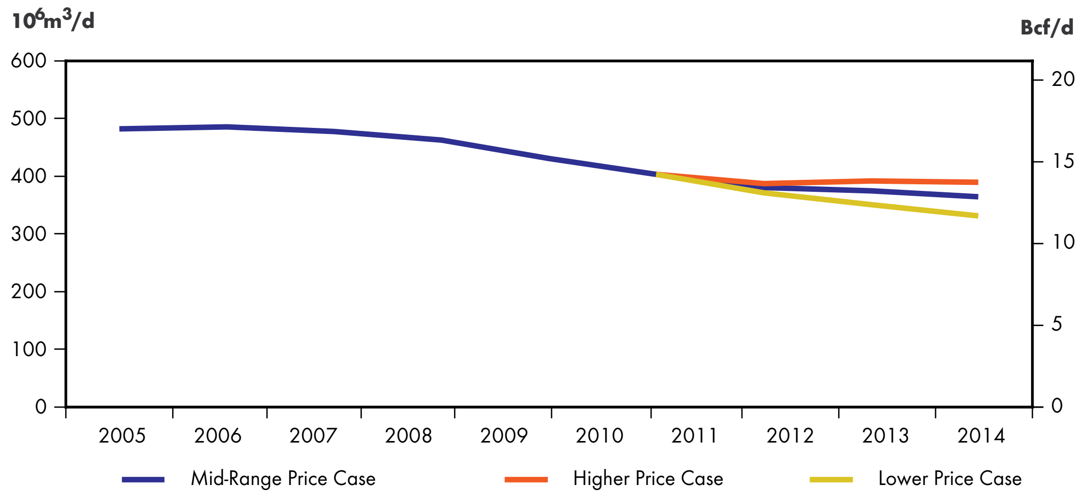
- Onshore production from New Brunswick, Ontario, Yukon, and Northwest Territories, which will continue to decline as minimal future drilling activity is expected over the projection period.
- The latest indication from the operator for the Deep Panuke offshore project in Nova Scotia calls for the project to begin producing natural gas in July 2012. The Deep Panuke volumes will help to offset ongoing declines in output from the Sable Island fields.
- Shale gas potential exists in Quebec; however, insufficient data is available. Consequently, this report does not show any natural gas deliverability throughout the projection period.

Deliverability Outlooks

The three price cases cover a range from a Lower Price Case where almost all drilling of natural gas is uneconomic unless the gas has a high NGL content, to a Higher Price Case where natural gas supply and demand move into balance and provide an incentive for the resumption of dry natural gas drilling. A Mid-Range Price Case is largely reliant on activity targeting NGL-rich gas as prices do not reach levels that would support much drilling for dry natural gas. A comparison of the three Canadian natural gas deliverability outlooks to 2014 under these alternative market conditions is shown in Figure 4.1.

FIGURE 4.1

Deliverability Results



The levels of drilling activity that provide these deliverability outcomes are the result of capital investment assumptions and estimates of drilling costs. A comparison of natural gas drilling activity in the three cases in terms of drill days and gas-intent wells drilled are shown in Figure 4.2 and Figure 4.3, respectively.

FIGURE 4.2

Natural Gas-Intent Drill Days Comparison

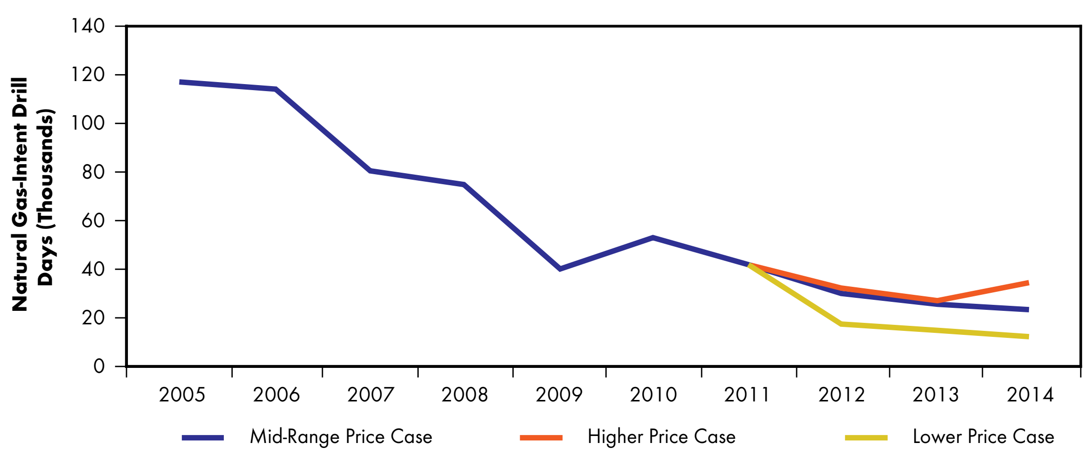
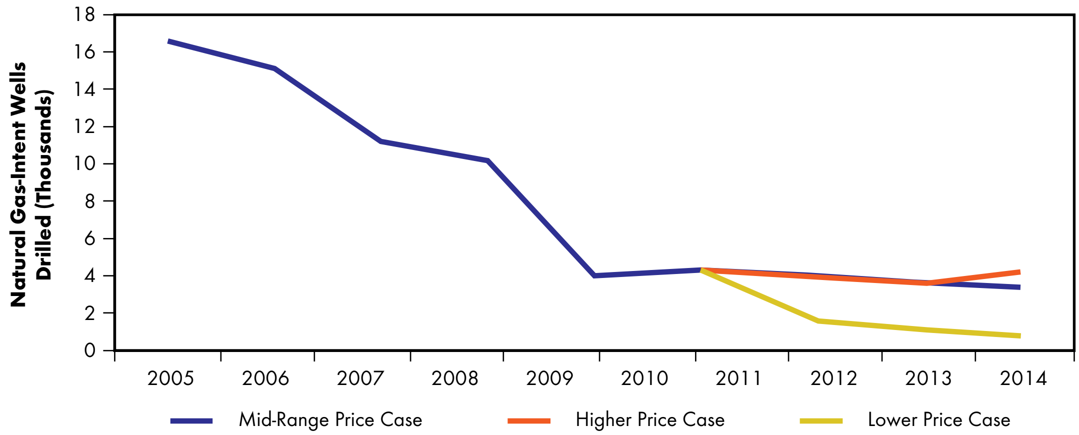


FIGURE 4.3

Natural Gas-Intent Wells Drilled Comparison



Mid-Range Price Case

For the Mid-Range Price Case, oversupply conditions continue to drive 2012 Canadian and U.S. natural gas prices below those experienced in 2011. After 2012, prices gradually rise, but not enough for much dry gas drilling to become economic. Producers would continue to reduce natural gas drilling, particularly for dry natural gas. With a decrease in overall natural gas drilling, Canadian production declines, and U.S. production growth slows. The demand for natural gas slowly increases, and as the amount of oversupply is reduced, natural gas prices begin to rise gradually. Increased oil targeted drilling will contribute additional gas to overall supply as oil production also brings on associated and solution gas, but total gas deliverability will still be less than in 2011. Liquids-rich natural gas drilling will take place in locations where NGL contents are high enough to make production economic.

Deliverability Results

In the Mid-Range Price Case, Canadian natural gas deliverability will continue to be well above Canadian demand. The rate of decline in overall deliverability slows slightly due to higher productivity wells coming on-stream. Tight gas and shale gas activity stabilizes in 2012 with 229 wells drilled in the Montney and 39 in Horn River. Horn River deliverability decreases from 16 $10^6 m^3/d$ (555 MMcf/d) in 2012 to 15 $10^6 m^3/d$ (522 MMcf/d) in 2014. Montney deliverability increases from 46 $10^6 m^3/d$ (1.62 Bcf/d) in 2012 to 55 $10^6 m^3/d$ (1.95 Bcf/d) in 2014.

Implications

Slowing gas drilling activity and rising natural gas demand would begin to reduce the oversupply conditions. Reduced drilling for dry natural gas is expected to occur in Canada and the U.S. Growth in Canadian natural gas demand would consume a greater proportion of the country's available deliverability, thereby reducing the net volumes available for export. Prices rise by U.S. $0.50 per MMBtu between 2011 and 2014.

TABLE 4.2

Mid-Range Price Case Summary and Results

	Average HH Price $US/MMBtu	Gas-Intent Drill Days	Gas-Intent Wells	Average Deliverability	
				$10^6m^3/d$	Bcf/d
2011	$4.00[1]		2782[2]	414[3]	14.6
2012	$3.75	32714	2159	410	14.5
2013	$4.25	30482	1755	397	14.0
2014	$4.50	26470	1384	373	13.2

1 EIA– Short Term Energy Outlook, 10 Jan 2012. http://www.eia.gov/forecasts/steo/data.cfm
2 PSAC Estimate – 26 January 2012.
3 Annual average of NEB reported provincial production, where available.

Full results of this case are available in Appendix C.

Higher Price Case

The Higher Price Case would see a closer balance between supply and demand before the end of the projection period. As natural gas prices rise, a movement back towards dry natural gas targeted drilling takes place, starting with liquids-rich gas in 2012 and 2013 followed by growth in dry natural gas targeted drilling in 2014. As natural gas prices rise, there may be less substitution of coal-fired electricity generation by natural gas.

Deliverability Results

Canadian natural gas deliverability declines more slowly than in the Mid-Range Price Case due to additional natural gas-intent drilling. Deliverability decreases from 414 $10^6m^3/d$ (14.6 Bcf/d) in 2011 to 385 $10^6m^3/d$ (13.6 Bcf/d) by 2014. Liquids-rich natural gas is still the primary source of new production, along with growing volumes of associated and solution gas. Even with a greater increase in price when compared to the Mid-Range Price Case, dry natural gas drilling will not be significant until 2014 when prices reach U.S. $6.00/MMBtu and shallower, less complex dry gas developments begins to attract some capital. Horn River deliverability increases from 17 $10^6m^3/d$ (597 MMcf/d) in 2012 to 18 $10^6m^3/d$ (617 MMcf/d) in 2014. Montney deliverability increases from 47 $10^6m^3/d$ (1.67 Bcf/d) in 2012 to 61 $10^6m^3/d$ (2.16 Bcf/d) in 2014.

Implications

In the Higher Price Case, the return of dry gas activity during a period of high oil activity would put additional pressure on the drilling and pressure pumping services in particular. Cost escalation could accelerate if shortages of labour, equipment, or materials were to become severe. When combined with ongoing increases in solution gas, associated gas, and NGL-rich gas production, additional natural gas drilling will slow the decline in overall deliverability. Overall growth in deliverability will not take place over the projection period, even though natural gas prices rise each year.

TABLE 4.3

Higher Price Case Summary and Results

	Average HH Price $US/MMBtu	Gas-Intent Drill Days	Gas-Intent Wells	Average Deliverability	
				$10^6m^3/d$	Bcf/d
2011	$4.00[1]		2782[2]	414[3]	14.6
2012	$4.75	34889	2297	413	14.6
2013	$5.25	31187	1761	403	14.2
2014	$6.00	33655	2118	385	13.6

1 EIA– Short Term Energy Outlook, 10 Jan 2012. http://www.eia.gov/forecasts/steo/data.cfm
2 PSAC Estimate – 26 January 2012.
3 Annual average of NEB reported provincial production, where available.

Full results of this case are available in Appendix C.

Lower Price Case

The Lower Price Case assumes a continuation of oversupply conditions due to significant contributions from solution gas, associated gas, and more U.S. NGL-rich gas. The Lower Price Case sees substantially less natural gas drilling activity than in the Mid-Range Price Case since most drilling in the Lower Price Case is supported solely by oil and NGL prices. Lower natural gas prices would impact drilling in areas with lesser NGL content as they would slip below the economic cut-off. The minimal dry gas drilling in the Mid-Range Price Case would be further discouraged.

Deliverability Results

Canadian natural gas deliverability declines steadily to 341 $10^6m^3/d$ (12.0 Bcf/d) in 2014, a decrease of 73 $10^6m^3/d$ (2.6 Bcf/d) from 2011, but is still well above Canadian demand. Lower natural gas prices would further reduce the attractiveness of investment in the sector.

Implications

Canadian natural gas consumers would benefit from lower natural gas prices. However, this case also shows the greatest decline in natural gas deliverability. Oil-related activity might be able to compensate for reduced natural gas operations to maintain Canadian drilling and service activity. The potential transition toward oil and away from natural gas would tend to shift some capital investment away from gas-prone B.C. and into oil-prone Saskatchewan, while the impact would be mixed in Alberta.

TABLE 4.4

Lower Price Case Summary and Results

	Average HH Price $US/MMBtu	Gas-Intent Drill Days	Gas-Intent Wells	Average Deliverability	
				$10^6m^3/d$	Bcf/d
2011	$4.00[1]		2782[2]	414[3]	14.6
2012	$2.50	19120	887	400	14.1
2013	$2.75	16030	637	372	13.1
2014	$3.00	14108	533	341	12.0

1 EIA– Short Term Energy Outlook, 10 Jan 2012. http://www.eia.gov/forecasts/steo/data.cfm

2 PSAC Estimate – 26 January 2012.

3 Annual average of NEB reported provincial production, where available.

Full results of this case are available in Appendix C.

Canadian Deliverability and Demand

The Board's outlooks for gas deliverability and Canadian gas demand over the projection period are included in Table 4.5. The Board projects annual Canadian natural gas demand to grow by 17 $10^6m^3/d$ (0.6 Bcf/d) between 2012 and 2014. Most of this increase in natural gas demand would be from increased usage for oil sands development in Alberta. Natural gas deliverability, even in the Lower Price Case, will exceed expected Canadian demand.

TABLE 4.5

Average Annual Canadian Deliverability and Demand

	2011		2012		2013		2014	
	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d
Canadian Deliverability, Mid-Price Case	414.0	14.6	409.9	14.5	396.8	14.0	372.8	13.2
Total Canadian Demand	252.1	8.9	260.6	9.2	266.3	9.4	277.6	9.8
Western Canada Demand	147.3	5.2	153.0	5.4	155.8	5.5	164.3	5.8
Eastern Canada Demand	104.8	3.7	107.6	3.8	110.5	3.9	113.3	4.0

Key Differences from Previous Projection

Comparing the actual performance in deliverability with the Board's most recent assessment, *Short-term Canadian Natural Gas Deliverability 2011-2013*, Canadian natural gas prices in 2011 tracked very close to the Board's Mid-Range Price Case, however, deliverability was higher than forecast and was above the Board's High Price Case.[8] This likely occurred for a few key reasons:

- A greater impact from price hedging than expected. Many producers were able to hedge their production at prices that were higher than market prices and this fostered additional gas targeted activity.
- Initial production rates in 2011 were higher than anticipated for some key groupings. For instance, new Horn River Basin shale wells and Montney tight gas wells produced at higher rates than expected. Higher initial production rates were due to selection of only the best prospects ("high-grading"). Advances in technology that included drilling longer horizontal well sections with a corresponding increase in the number of hydraulic fracture stages per well, also contributed to higher production rates.
- Efficiency improvements such as drilling multiple wells from a single pad reduced costs by allowing wells to be drilled more quickly.

8 National Energy Board. *Short-term Canadian Natural Gas Deliverability 2011-2013*, Available at www.neb-one.gc.ca.

RECENT ISSUES AND CURRENT TRENDS

Listed below are developments that will affect future North American natural gas deliverability.

- After three years of natural gas production declines, Canadian natural gas production stabilized in 2011 despite a modest decline in drilling activity from 2010. The key reason was a transition to higher productivity wells in shales and deeper horizons in B.C. and in western Alberta.
- The rise in oil-related activity is likely to cause cost inflation in an active Western Canadian drilling and service industry, which will affect both gas and oil producers. Higher rates for oil and gas services will affect levels of future drilling.
- Some large international companies with existing Canadian operations have focused their activity on liquids-rich shale assets in the U.S. at the expense of Canadian activities. Many of Canada's gas producers also have international operations with diverse portfolios. Canadian prospects have to compete with international prospects for investment capital.
- Activity could slow in British Columbia's Horn River Basin as companies producing the dry gas do not benefit from NGL revenues.
- Other Canadian shale gas plays such as the Cordova Embayment in northeastern B.C., and the Duvernay in Alberta, are at an early stage of development and modest levels of drilling are expected to evaluate the resources and determine the most effective drilling and completion techniques.
- U.S. horizontal drilling for shale gas has increased since 2008 despite a significant decline in prices. In recent years, this may have been largely due to the need to drill and produce gas to retain leases. With land from the peak leasing years now largely held by production, the need to drill dry gas wells for this purpose is expected to drop over the 2012 to 2014 period.
- The objective of widespread use of best practices in hydraulic fracturing, integrity of well casing, water use, and disposal, may include additional monitoring and regulations that could affect activity and increase costs.
- Increases in Canadian and U.S. natural gas demand may gradually offset the rise in U.S. shale gas production and accelerate a return to a more balanced market. The level of natural gas demand is dependent on a number of both independent and interrelated factors, such as the pace of economic growth, electricity demand, and the pace of oil sands development.
- Canadian and U.S. weather patterns have a large influence on natural gas demand for space heating and cooling. Temperatures in the 2010-2011 winter were far below normal, which contributed to a large increase in heating requirements and gas demand. The summer months in 2011 were very warm and increased gas demand for electricity generation to run air conditioners. Conversely, winter temperatures in 2011-2012 were well above normal and reduced gas demand. Due to the unpredictability of weather, an assumption of normal weather conditions is used in this analysis.

A P P E N D I C E S

Appendix A

A1	Methodology (Detailed Description)
A2	Deliverability Parameters - Results
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B1	Factors for Allocation of Gas-Intent Drill Days to Areas
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Short-term Canadian Natural Gas Deliverability

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NE2-1/2012E-PDF
ISSN: 1910-7773

This report is published separately in both official languages. This publication is available upon request in multiple formats.

NE2-1/2012F-PDF
ISSN: 1910-779X

Ce rapport est publié séparément dans les deux langues officielles. On peut obtenir cette publication sur supports multiples, sur demande.

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APPENDIX A

A1 Methodology (Detailed Description)

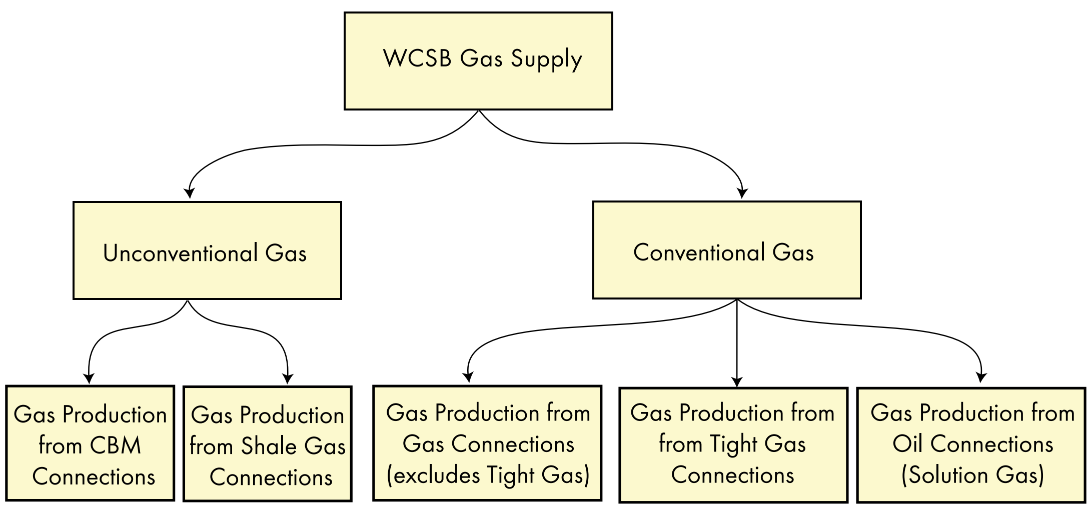
Canadian natural gas deliverability from 2012 to 2014 will consist of conventional gas supply from the WCSB with contributions from Atlantic Canada, Ontario, Northwest Territories, Yukon, CBM production from Alberta, and shale gas production from BC. In this report, an analysis of trends in well production characteristics and resource development expectations was undertaken to develop parameters that define future natural gas deliverability from the WCSB. A different approach was undertaken for other regions of Canada where production is sourced from a smaller number of wells.

A1.1 WCSB Gas Supply

To assess gas deliverability for the WCSB, gas production was split into two major categories as shown in Figure A1.1.

FIGURE A1.1

WCSB Major Gas Supply Categories for Deliverability Assessment



The methodology to determine gas deliverability associated with conventional gas connections (including tight gas), CBM connections, and shale gas is described below. Tight gas is reported as conventional gas in this report, due to the lack of clear and widely recognized criteria that would enable the segregation of tight gas connections. The methodology to determine gas deliverability related to oil connections (solution gas) is described in section A1.1.2 of this appendix.

A1.1.1 Gas Connections from Gas Wells

The methodology used to assess deliverability is mostly the same for conventional gas connections (including tight gas) and CBM connections. Production decline analysis on historical production data was used to determine parameters that define future performance. In the case of CBM, Horn River shale gas, and Montney tight gas, historical data is more limited, so the views gathered in consultations with industry played a larger role in establishing the performance parameters.

A1.1.1.1 Groupings for Production Decline Analysis

Different groupings of conventional gas connections (including tight gas), shale gas, and CBM connections were made to assess well performance characteristics. Conventional gas connections were grouped geographically on the basis of the Petrocube areas in Alberta, B.C., and Saskatchewan, as shown in Figure A1.2. Conventional gas connections in each area were also grouped by zone. In this analysis, gas deliverability from the Montney formation includes all gas produced from the Triassic period. This is due to the rapid increase and overall proportion of deliverability that has taken place over the past half decade that has seen the Montney (and Doig) formations dominating deliverability out of the Triassic. While some of the other formations within the Triassic period (Baldonnel, Charlie Lake, Boundary Lake, and Halfway) do not have the same geological characteristics as the Montney (and Doig) formations their recent overall deliverability has decreased significantly.

FIGURE A1.2

WCSB Area Map

Within each Petrocube area and zone, gas connections were grouped by connection year, with all connections made prior to 1999 forming a single grouping, and separate groupings for each year from 1999 through 2010.

CBM connections were grouped primarily by zone into three categories:

- Horseshoe Canyon Main Play
- Mannville CBM, and
- Other CBM

For the projection period, CBM development is expected to occur only in Alberta.

Within each of the three categories of CBM resources, connections were also grouped by connection year. Due to the short period of commercial production, there are fewer connection year groupings. For the Horseshoe Canyon Main Play and Other CBM categories, there is a single grouping for all connections made prior to 2004, and separate groupings for each year from 2004 through 2010. For Mannville CBM, a single grouping was made for all connections made prior to 2006, and separate groupings for each following year.

Existing Connections vs. Future Connections

In this report, “existing connections” are connections brought on production prior to January 1, 2011, and “future connections” are connections brought on production from January 1, 2011 onwards. The methodology applied to make the gas deliverability projections for existing connections is substantially different from what is done to assess deliverability for future connections.

A1.1.1.2 Methodology for Existing Connections

For **existing connections**, production decline analysis on historical production data is done on each grouping (gas type/study area/zone/connection year) to develop two sets of parameters.

1. Group deliverability parameters-- describing deliverability expectations for the entire gas resource grouping.
2. Average connection deliverability parameters-- describing deliverability expectations for the average gas connection in the grouping (note—these only apply when the grouping represents a specific connection year).

The methodology for the production decline analysis on existing connections is described below. The group deliverability parameters and average connection deliverability parameters resulting from this analysis are contained in Appendix A.3. In the deliverability model, the group deliverability parameters are used to make the deliverability projection for existing connections.

Production Decline Analysis Methodology

The production decline analysis procedure described below applies to conventional gas connections (including tight gas), and CBM in the WCSB.

Conventional gas connections are grouped by study area, zone, and connection year. CBM connections in Alberta are grouped by producing zone and connection year. For each of these groupings, a data set of group marketable production history is created and, where the grouping represents a specific connection year, a data set of average connection marketable production history is also generated.

The data sets for group marketable production are generated as follows:

- Raw well production for gas connections in each grouping is summed by calendar month getting total group raw production by calendar month.
- The total group raw production by calendar month is multiplied by an average shrinkage factor that applies to the grouping and divided by the number of days in each month to get total monthly marketable gas production and marketable gas production rate (MMcf/d) for each calendar month.
- Using this data set, plots of total daily marketable production rate versus total cumulative marketable production are generated for each grouping.

The data sets for average connection production history are created as follows.

- The raw well production by month for each connection in the grouping is put in a database.
- For each entry of production month for each connection, a value of normalized production month is calculated as the number of months between the month the connection began producing and the actual production month (this is the normalized production month).
- The raw production for connections in the grouping is summed by normalized production month and then multiplied by the average shrinkage factor that applies to the grouping, providing total marketable production by normalized production month.
- The total marketable production by normalized production month is then divided by the total number of connections in the grouping to get marketable production for the average connection by normalized production month.
- The marketable production for normalized production month is then divided by the average number of days in a month, or 30.4, giving the production rate for the average connection in the grouping by normalized production month (Note: due to the different number of production months for connections in the grouping coming on stream at different times of the year, some production data could not be used in the calculation of the average connection production rate).
- Using this data set, plots of daily marketable production rate versus cumulative marketable production for the average connection were generated for each grouping.

For conventional gas connections, the following procedures are applied in performing production decline analysis using the group and average connection historical production data sets:

- **Production Decline Analysis for the Pre-1999 Connections**

  In each study area, the rate versus cumulative production plot for the grouping of gas connections on production prior to 1999 is the first to be evaluated. In all study areas, a stable exponential decline for the past several years was exhibited. The group plot for all the connections prior to 1999 yields a current marketable production rate, a stable decline rate applicable to future production, and a terminal decline that may be applicable to later connection year groupings for the study area.

- **Evaluate Connection Year 1999 through 2010**

  After the initial aggregate connection year is evaluated for a study area, each connection year is evaluated in sequence, from 1999 through 2010.

  a. **Production Decline Analysis for the Average Connection:**

  For each connection year, the rate versus cumulative production plot for the average connection is evaluated first to establish the following parameters that describe the production profile of the average connection over the entire productive life:

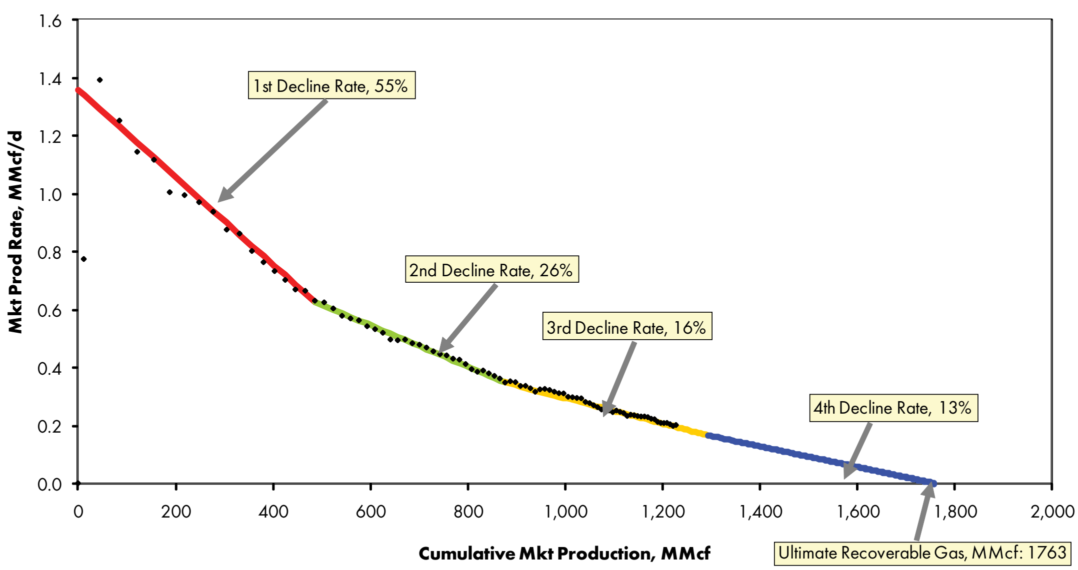
  - Initial Production Rate
  - First Decline Rate
  - Second Decline Rate
  - Months to Second Decline Rate- usually around 18 months
  - Third Decline Rate
  - Months to Third Decline Rate- usually around 45 months
  - Fourth Decline Rate
  - Months to Fourth Decline Rate- usually around 100 months.

  Figure A1.3 shows an example of the plots used in evaluation of average connection performance, and the different decline rates that are applied to describe the production.

  For the earlier connection years, the available data is usually sufficient to establish all of the above parameters. For more recent connection years, the duration of historical production data becomes shorter and the parameters describing the later life decline performance must be taken from that determined for earlier connection years. In the example shown in Figure A1.3, the available data is sufficient to determine parameters

FIGURE A1.3

Example of Average Connection Production Decline Analysis Plot



Source: NEB analysis of Divestco Geovista well production data defining the first, second, and third decline periods for the connection, but the parameters defining the fourth decline period must be assumed based on the analysis of earlier connection years.

It is assumed that, unless the historical data for the connection year indicates otherwise, the fourth decline rate will equal the terminal decline rate for the grouping established through evaluation of all pre-1999 connections, and that period of the terminal decline rate will commence after 120 months of production.

The decline parameters determined in this manner for average connections are available in Appendix A4.

b. **Production Decline Analysis for the Group Data:**

Once the performance parameters for the average connection are established, the procedure focuses on evaluation of group performance parameters.

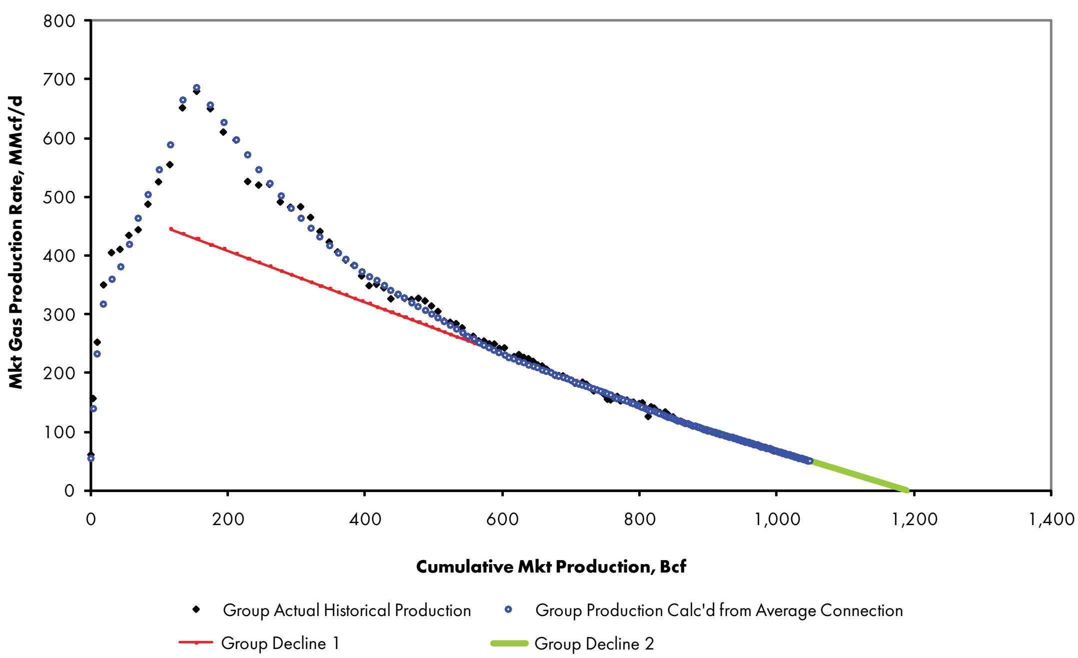
As a first step, the average connection performance parameters are combined with the known connection schedule to calculate the expected group performance. This is plotted with the actual group performance data. If the data calculated from average connection performance data does not provide a good match with the actual historical production data for the group, then the average connection parameters may be revised until a good match is obtained between calculated group production data (from average connection data) and actual group production data. An example of the group plots described here is shown in Figure A1.4.

The following group performance parameters are determined from the group plot:

- Production Rate as of December 2010
- First Decline Rate

FIGURE A1.4

Example of Group Production Decline Analysis Plot



Source: NEB analysis of Divestco Geovista well production data

- Second Decline Rate (if applicable)
- Months to Second Decline Rate (if applicable)
- Third Decline Rate (if applicable)
- Months to Third Decline Rate (if applicable)
- Fourth Decline Rate (if applicable)
- Months to Fourth Decline Rate (if applicable)

In the earlier connection year groupings (2001, 2002, etc.), the actual group data is usually stabilized by the current date at or near the terminal decline rate established via the pre-1999 aggregate grouping. In these cases a single decline rate sufficiently describes the entire remaining productive life of the grouping. In these cases the expected performance calculated from average connection data has little influence over determination of the group parameters.

In later connection years (2009, 2010, etc.) actual group production history data cannot provide a good basis upon which to project future deliverability. In these cases the expected performance calculated from average connection data is vital to establishing the current and future decline rates applicable for the connection year.

Group performance parameters determined in this manner are available in Appendix A3.

Production Decline Analysis of CBM

The production decline analysis procedure described above is also applied to the CBM groupings, subject to the following:

1. The short production history of CBM in Alberta makes it difficult to establish long term decline rates based on historical data, especially with regard to Mannville CBM. Nevertheless, decline rates that describe the full productive life of CBM connections are still estimated in this EMA, based on industry consultations, and on the NEB's view of ultimate gas recovery for the average connections for the different CBM groupings.
2. Mannville CBM connections have a different performance profile than the other gas resources in the WCSB. While gas connections for all other groupings can be described by an initial production rate that declines in a relatively predictable manner, Mannville CBM connections go through a dewatering phase with gas production increasing over a period of months to a peak rate. After the peak rate is reached decline will occur. Thus a slightly different set of parameters is used to describe performance of the average connection for Mannville CBM, with initial production rate being replaced by "Months to Peak Production" and "Peak Production Rate".

A1.1.1.3 Methodology for Future Connections

For future connections, deliverability is projected based on the number of future connections and the expected average performance characteristics of those connections. The drilling projection is used to estimate the number of future gas connections. Historical trends in average connection performance parameters, obtained from production decline analysis of existing gas connections, are used to estimate average connection performance parameters for future connection years.

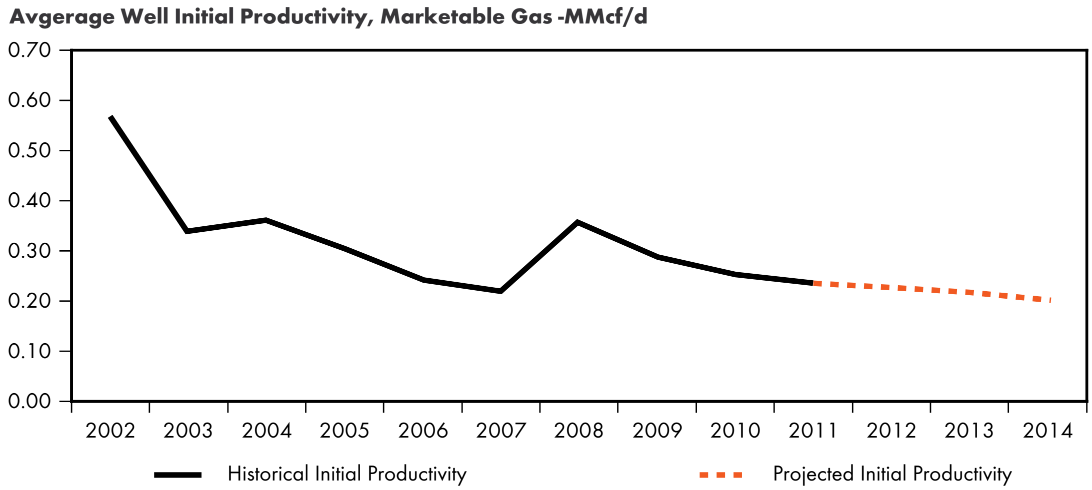
A1.1.1.3.1 Performance of Future Connections

The performance of future connections is obtained in each resource grouping by extrapolating the production performance trends for average connections in past connection years. The performance parameters estimated are initial productivity of the average connection and the associated decline rates.

In some groupings, each new connection year follows a trend of decreasing initial productivity for the average conventional gas connection. This trend is evident in Figure A1.5, which shows the initial production rate over time for conventional gas connections in the Southern Alberta Mannville conventional grouping. Recently, however, there has been a trend in some tight and shale groupings where initial productivity for the average gas connection has been increasing. The Initial Production Rate for future gas connections is estimated by extrapolating the trend in each resource grouping. Historical and projected initial productivity values for the average connection for all gas resource groupings are contained in Appendices A3 and A4.

FIGURE A1.5

Example of Initial Productivity of Average Connections by Connection Year
Southern Alberta Mannville Conventional Grouping



Source: NEB analysis of Divestco well production data

The key decline parameters impacting short-term deliverability are the first decline rate, second decline rate, and months to second decline rate. Figure A1.6 shows the historical and projected values of these key decline parameters for the average connections during the years 2002 through 2014 for conventional gas connections in the Southwest Alberta, Tertiary, Upper Cretaceous, Upper Colorado grouping. As shown in Figure A1.6, trends seen in the decline parameters in past connection years are used to establish these key parameters for future years.

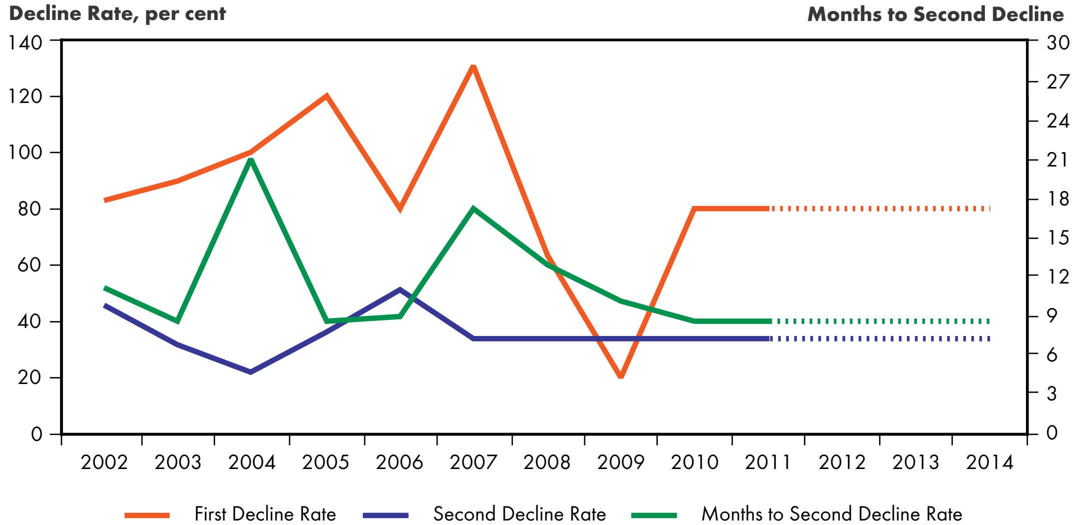
A1.1.1.3.2 Number of Future Connections

The number of future connections is forecast by first making a projection of the annual number of gas-intent (including tight gas), shale-intent, and CBM-intent wells for each resource grouping and then multiplying by the ratio of annual connections to annual wells.

The methodology for projecting the number of gas-intent and CBM-intent wells for each year over the projection period is shown in Figure A1.7. The key inputs are **Annual Drilling Investment** and **Costs per Drill Day**. These two key inputs (shown as yellow boxes in Figure A1.7) are adjusted to produce different drilling activity cases in the WCSB. Other inputs required by the procedure are

FIGURE A1.6

Example of Key Decline Parameters for Average Connections over time
Southwest Alberta, Tertiary, Upper Cretaceous, Upper Colorado Conventional Grouping



shown as green boxes in Figure A1.7. The values projected for these other inputs are estimated from an analysis of historical data.

The drilling projection provides the number of gas-intent drill days that target each resource grouping. The Board projects an allocation of gas-intent drill days for each of the resource groupings. The allocation fractions are determined from historical trends, recent estimates of supply costs, and the Board's view of development potential for the resource groupings. The allocation fractions reflect the historical trends of an increasing focus on the deeper formations located in the western side of the basin, increasing interest in tight gas and B.C. shale gas, and further development of liquids rich/ wet natural gas. Tables of the historical data (drill days and allocation fractions) and the projected allocation fractions are available in Table B1.

After allocating the gas-intent drill days to the resource groupings, a check is completed against drilling capacity to ensure that physical drilling limitations are not exceeded. The number of gas-intent wells drilled in each year is calculated by dividing the drill days targeting each resource grouping by the applicable average number of drill days per well.

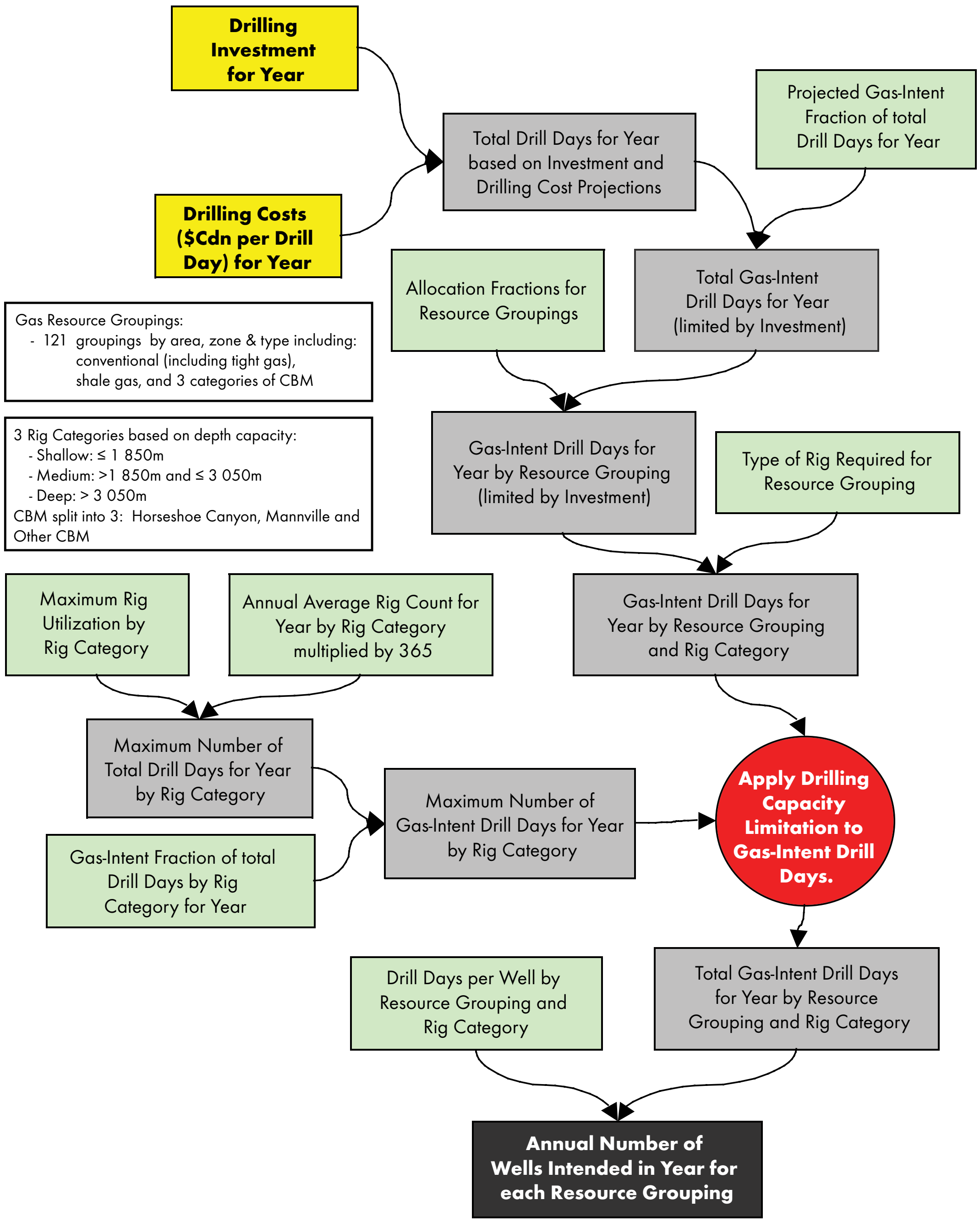
For each resource grouping, a connection ratio (the ratio of annual connections to annual wells drilled targeting a grouping) is estimated based on historical data. The annual number of wells drilled is multiplied by the connection ratio to obtain the number of annual connections for each resource grouping. The connection ratios for each resource grouping are provided in Table B.2. The annual number of connections for each resource grouping is allocated to each month of the year in accordance with the established historical connection schedule.

A1.1.2 Solution Gas

Solution gas is produced from oil wells in conjunction with the crude oil and accounts for about nine per cent of total marketable gas production in the WCSB. To estimate deliverability of solution gas, oil connections are grouped by study area and production decline analysis is performed on the entire

FIGURE A1.7

Flowchart of NEB Drilling Projection Methodology



grouping to obtain the current production rate and the decline rate. The deliverability resulting from these parameters is deemed to represent all solution gas deliverability (i.e. deliverability from both existing and future connections).

A1.1.3 Yukon and Northwest Territories

In the Yukon and Northwest Territories, conventional gas is produced to the pipeline grid from two pools close to the territorial border of 60 degrees north latitude. These two pools (or fields) are

Kotaneelee and Cameron Hills. Much further to the north, the Ikhil and Norman Wells fields also produce small amounts of gas that serve local purposes and are not tied into the North American pipeline grid. With the limited number of producing wells and development activity in the Kotaneelee and Cameron Hills areas, production decline analysis for the existing gas connections provides a good estimate of future deliverability. No deliverability from the Mackenzie Delta and elsewhere along the Mackenzie Corridor is included during the three year projection period.

In this report, gas deliverability of the southerly fields tied in to the pipeline grid is represented as total deliverability from the Yukon and Northwest.

A1.2 Atlantic Canada

For producing wells from offshore Nova Scotia, production profiles are based on an average of the decline rates in the five producing fields. No additional infill wells are assumed for the producing fields over the projection period. Offshore compression was fully in service by May 2007. The parameters used in the compression analysis are based on discussions with industry representatives. Deliverability from the Deep Panuke development, as stated by the operator, is expected to begin in July 2012.

Onshore production from the McCully Field in New Brunswick was connected into the regional pipeline system at the end of June 2007. Future development and performance of the field is based on corporate development plans and industry consultations, and takes into consideration the performance of existing wells.

Due to the early stage of assessment and lack of data, reasonable estimates of onshore CBM and shale gas deliverability in Nova Scotia and New Brunswick cannot be developed at this time.

A1.3 Other Canadian Production

The WCSB, Yukon and Northwest Territories, and Atlantic Canada discussed in the preceding sections of this chapter account for almost all of Canada's deliverability. The minor remaining amount of Canadian deliverability is from Ontario. Deliverability from Ontario is projected by extrapolation of historical production volumes. Quebec natural gas deliverability is not included in the projection due to insufficient data.

A1.4 Canadian Deliverability and Canadian Demand

For a better understanding of the role of natural gas deliverability in relation to the Canadian natural gas market, it is useful to compare the Board's outlook for deliverability with current and anticipated Canadian natural gas demand.

Natural gas deliverability is defined as the estimated amount of gas supply from a given area, after field processing, based on historical production and individual well declines, as well as projected activity. All estimated gas use prior to the outlet from field processing plants has already been deducted from the deliverability estimate, and likewise is not included in the demand estimate. Gas consumed at the Goldboro processing facility in Nova Scotia is in this category of field processing and has therefore already been deducted from Atlantic Canada deliverability.

Current and projected Canadian gas demand is divided geographically at the Saskatchewan-Manitoba border into Western and Eastern Canada demand. Western Canada demand includes gas volumes withdrawn during the recovery of natural gas liquids at straddle plants. Approximately 85 to 90 per cent of the gas volumes leaving Alberta are processed through the straddle plants, where much of the ethane in the gas stream is extracted along with traces of other NGLs and heavier components remaining after field processing. A table of the Average Annual Canadian Deliverability and Demand is available in Appendix E.

Canadian gas demand includes gas required for pipeline fuel in the respective areas. The Board's projection of Canadian gas demand is based on historical trends and expected major increments of gas-fired power generation and industrial projects (including oil sands developments). The demand projection is based on the assumption of average weather conditions. Considerable variability in actual gas demand is possible due to the impact of weather variation on Canada's space heating and cooling needs.

A2 Deliverability Parameters - Results

A2.1 WCSB

Using the Board's methodology, connections in the WCSB are categorized as either gas or oil. Gas connections are further categorized as conventional (including the tight gas sub-category), and unconventional (including shale gas and CBM). Connections are grouped based on geographical area, producing zone, and connection year, with different grouping criteria applied to different types of connections.

In the case of existing gas connections (those on production prior to 1 January, 2011), and all oil connections (solution gas), production decline analysis is used to establish parameters that define future deliverability of each grouping. Section A2.1.1 below provides further discussion of the parameters resulting from the production decline analysis.

For future gas connections (those on production after 1 January, 2011), the number of expected future connections and the expected production performance of those future connections is estimated to provide a basis for the deliverability projection. Section A2.1.2 below provides discussion of the parameters used to project deliverability for future gas connections.

A2.1.1 Production from Existing Gas Connections

The future deliverability of existing connections of the resource groupings comprising conventional (including tight gas), and unconventional (including shale gas and CBM), and all solution gas was determined via the production decline analysis procedure described in Appendix A3. The decline parameters describing the expected future deliverability of each grouping are listed in Appendix A3.

The deliverability parameters for these groupings are not impacted by the different price cases considered in this report. The different price cases are included to reflect uncertainty in future gas drilling activity only.

The parameters describing future deliverability for all of these groupings are the production rate as of December 2010 and as many as four future decline rates that apply to specified time periods in the future. For the older groupings of wells where production appears to have stabilized at a final decline rate, only one future decline rate is needed to describe future group deliverability. For newer well groupings, the decline rate that applies over future months changes as the group performance progresses towards the final stable decline period. For these newer well groupings, three or possibly four different decline rates have been determined to describe future performance.

The future deliverability projected for these groupings represents the deliverability that would occur from the WCSB if there were no further gas connections made after the end of 2010. Deliverability projections made in previous reports for these categories of groupings have proved to be very close to actual performance.

The Board's projections show that aggregate production for these groupings will decline by 17 per cent over 2011, by a further 14 per cent in 2012, 14 per cent in 2013, and 13 per cent in 2014. Deliverability from future gas connections supplements the declining deliverability from existing connections.

A2.1.2 Future Gas Connections

Deliverability associated with future gas connections is calculated for each resource grouping using estimates for production performance of the average connection and the number of connections in future years. The parameters associated with both of these inputs are discussed in the sections below.

While past deliverability projections for existing gas connections have enjoyed a high degree of accuracy, the certainty associated with the projections for future gas connections is less. The key uncertainty is the level of gas drilling that will occur. Three price cases have been created to address the uncertainty inherent in the gas drilling projections.

A2.1.2.1 Performance Parameters for Future Average Gas Connections

The production decline analysis procedures described in Appendix A.1 provide the basis for establishing performance parameters for future gas connections. The trends seen in average connection performance for the various groupings of existing connections are used to make an estimate of performance parameters for future gas connections.

For conventional gas connections (including tight gas), the connections are grouped based on area, formation, and connection year from 1999 through 2010. These 12 connection year groupings are assessed for each grouping, providing an excellent historical data set to estimate performance of future wells.

Two trends are apparent in the performance parameters for the existing conventional gas connections.

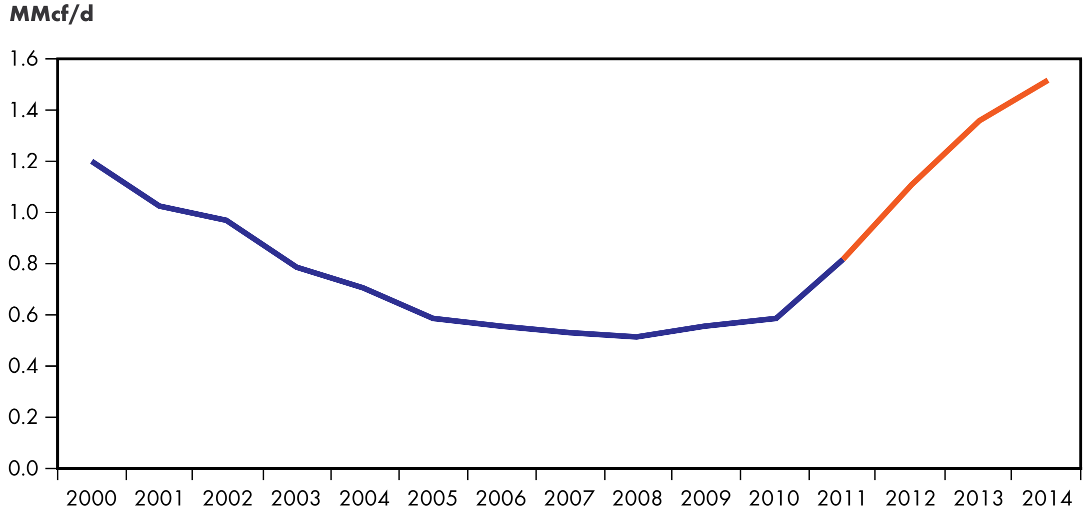
- Decline rates applicable to the average connection are quite stable over the past several connection years.
- Initial productivity of the average connection increases from connection year to connection year.

With respect to initial productivity of the average gas connection, the overall trend for the WCSB is shown in Figure A2.1. After decreases in initial productivity over 2000 to 2007, the trend reversed upwards for 2008, and continues upwards through to 2014 as higher initial productivity rates from tight gas and shale gas wells begin to represent a growing share of the wells drilled in a year.

Table A2.1 shows the historical average initial production rates for the average gas connections for each area. Appendices A3 and A4 provide a complete listing of all performance parameters for average connections by grouping for both historical and future connection year groupings.

FIGURE A2.1

WCSB Initial Productivity of Average Conventional Gas Connections by Connection Year



Source: NEB Analysis of Divestco Well Production Data

TABLE A2.1

WCSB Initial Productivity of Average Gas Connections by Connection Year by Area - MMcf/d

Area	2004	2005	2006	2007	2008	2009	2010
00 - Alberta CBM	0.066	0.074	0.101	0.102	0.096	0.064	0.048
01 - Southern Alberta	0.158	0.135	0.107	0.098	0.114	0.104	0.131
02 - Southwest Alberta	0.308	0.235	0.232	0.227	0.304	0.288	0.233
03 - Southern Foothills	1.115	1.252	1.181	0.342	0.151	0.683	
04 - Eastern Alberta	0.091	0.089	0.071	0.071	0.076	0.091	0.090
05 - Central Alberta	0.290	0.201	0.191	0.202	0.187	0.198	0.133
06 - West Central Alberta	0.389	0.408	0.349	0.411	0.494	0.410	0.561
07 - Central Foothills	1.558	1.820	1.179	1.611	1.667	1.565	1.076
08 - Kaybob	0.570	0.574	0.629	0.563	0.555	0.852	0.724
09 - Alberta Deep Basin	0.999	0.784	0.468	0.825	0.738	1.016	1.038
10 - Northeast Alberta	0.182	0.180	0.145	0.163	0.162	0.148	0.142
11 - Peace River	0.662	0.654	0.450	0.561	0.538	0.645	0.795
12 - Northwest Alberta	0.424	0.373	0.318	0.268	0.391	0.731	0.334
13 - BC Deep Basin	1.340	0.750	1.239	1.037	1.180	0.901	1.455
14 - Fort St. John	0.647	0.734	0.476	0.720	0.590	0.898	0.509
15 - Northeast BC	1.051	0.788	0.581	0.472	0.679	0.469	1.323
16 - BC Foothills	3.272	1.855	2.945	2.556	1.925	1.246	1.719
17 - Southwest Saskatchewan	0.058	0.071	0.070	0.057	0.054	0.061	0.040
18 - West Saskatchewan	0.150	0.137	0.118	0.125	0.093	0.138	0.095
Total WCSB	0.702	0.585	0.571	0.548	0.526	0.553	0.580

Source: NEB Analysis of Divestco Well Production Data

The average connection performance parameters projected for connection years 2011 through 2014 are the same in all three price cases assessed in this report. Variance between the cases is affected by applying different levels of gas drilling activity as discussed further in section 1.2.2 of this appendix.

A2.1.2.2 Number of Future Gas Connections

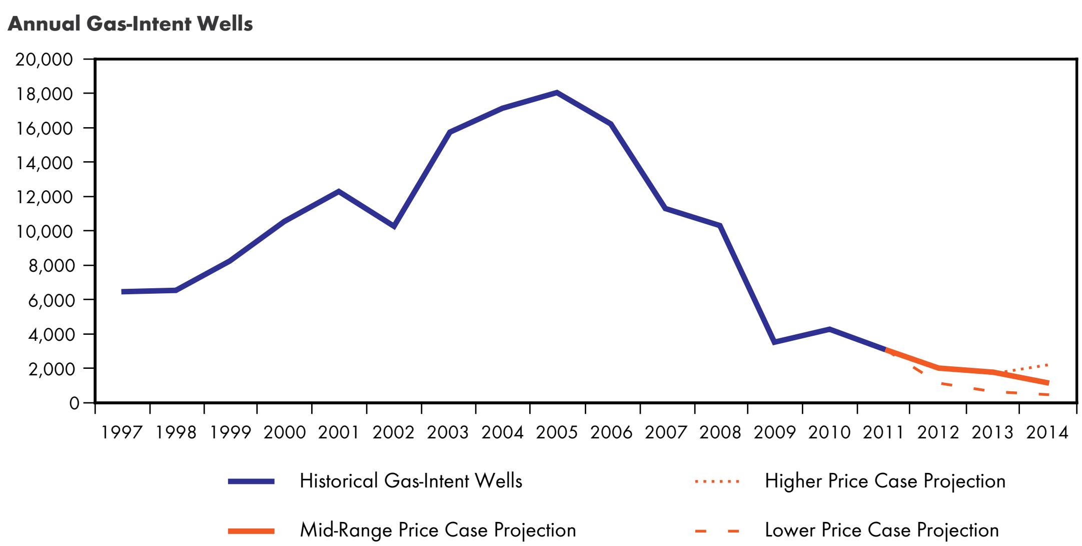
The projected number of connections by year and the projected production performance of the average connections in those years are applied to provide deliverability associated with future gas connections. To determine the number of future gas connections, projections of gas-intent drilling are made for each of the resource groupings. The annual number of wells targeted to each grouping is applied to the ratio of annual connections to annual wells for that grouping to provide the annual number of connections.

Volatile and unpredictable market conditions are expected to be the primary influence on gas-intent drilling activity. As a result, there is a high degree of uncertainty in the gas drilling activity that might occur in the coming years. Three drilling activity cases (Mid-Range, Higher, and Lower) that are based on projections of gas price reflect a range of market conditions that may occur over the projection period. Figure A2.2 indicates the projected number of gas-intent wells for all resource grouping in each case.

Detailed tabulations of projected annual gas-intent-wells, connection ratios, and annual connections for each resource grouping for each case are provided in Table B2.

FIGURE A2.2

WCSB Gas-Intent Drilling Cases



A2.2 Atlantic Canada, Ontario, and Quebec

As indicated in Appendix A1, deliverability from Atlantic Canada and Ontario is based on extrapolation of prior trends. No new major drilling activities are assumed over the 2012 to 2014 period that would contribute to deliverability at this time.

Marketable production from the Deep Panuke development, as stated by the operator, is expected to start in July 2012.

Future development and performance of the McCully field in New Brunswick is based on corporate development plans and consultations with industry. No major additional drilling is expected over the projection period.

Testing of onshore CBM and shale gas prospects is ongoing in Atlantic Canada. Due to the early stage of development, reasonable estimates of onshore CBM productivity cannot be developed due to a lack of data.

Deliverability from Ontario continues to decline with no major additional drilling expected over the projection period.

Shale gas potential exists in Quebec; however, insufficient data is available. Consequently, this report does not show any natural gas deliverability throughout the projection period.

A3 Decline Parameters for Groupings of Existing Gas Connections

Table A3.1 - Formation Index

Formation	Abbreviation	Group Number
Tertiary	Tert	02
Upper Cretaceous	UprCret	03
Upper Colorado	UprCol	04
Colorado	Colr	05
Upper Mannville	UprMnvl	06
Middle Mannville	MdlMnvl	07
Lower Mannville	LwrMnvl	08
Mannville	Mnvl	06;07;08
Jurassic	Jur	09
Upper Triassic	UprTri	10
Lower Triassic	LwrTri	11
Triassic	Tri	10;11
Permian	Perm	12
Mississippian	Miss	13
Upper Devonian	UprDvn	14
Middle Devonian	MdlDvn	15
Lower Devonian	LwrDvn	16
Horseshoe Canyon	HSC	–
Mannville CBM	Mannville	–

Table A3.2 - Grouping Index

Area name	Area Number	Resource Type	Resource Group
CBM Area	00	CBM	Main HSC
CBM Area	00	CBM	Mannville
Southern Alberta	01	Conventional	Tert;UprCret;UprColr
Southern Alberta	01	Conventional	Colr
Southern Alberta	01	Conventional	Mnvl
Southern Alberta	01	Tight	UprColr
Southwest Alberta	02	Conventional	Tert;UprCret;UprColr
Southwest Alberta	02	Conventional	Colr
Southwest Alberta	02	Conventional	MdlMnvl;LwrMnvl
Southwest Alberta	02	Conventional	Jur;Miss
Southwest Alberta	02	Conventional	UprDvn
Southwest Alberta	02	Tight	UprColr
Southwest Alberta	02	Tight	Colr
Southwest Alberta	02	Tight	LwrMnvl
Southern Foothills	03	Conventional	Miss;UprDvn
Eastern Alberta	04	Conventional	UprCret;UprColr

Area name	Area Number	Resource Type	Resource Group
Eastern Alberta	04	Conventional	Colr;Mnvl
Eastern Alberta	04	Tight	UprColr
Central Alberta	05	Conventional	Tert;UprCret
Central Alberta	05	Conventional	Colr
Central Alberta	05	Conventional	Mnvl
Central Alberta	05	Conventional	Miss;UprDvn
Central Alberta	05	Tight	Colr
Central Alberta	05	Tight	Mnvl
West Central Alberta	06	Conventional	Tert
West Central Alberta	06	Conventional	UprCret;UprColr
West Central Alberta	06	Conventional	Mnvl
West Central Alberta	06	Conventional	LwrMnvl; Jur
West Central Alberta	06	Conventional	Miss
West Central Alberta	06	Conventional	UprDvn
West Central Alberta	06	Tight	Colr
West Central Alberta	06	Tight	Mnvl
Central Foothills	07	Conventional	UprColr
Central Foothills	07	Conventional	Colr;Mnvl
Central Foothills	07	Conventional	Jur;Tri;Perm
Central Foothills	07	Conventional	Miss
Central Foothills	07	Conventional	UprDvn;MdlDvn
Central Foothills	07	Tight	UprColr;Colr
Central Foothills	07	Tight	Mnvl
Central Foothills	07	Tight	Jur
Kaybob	08	Conventional	UprColr;Colr
Kaybob	08	Conventional	Mnvl;Jur
Kaybob	08	Conventional	Tri
Kaybob	08	Conventional	UprDvn
Kaybob	08	Tight	Colr;Mnvl
Kaybob	08	Tight	Tri
Alberta Deep Basin	09	Conventional	UprCret
Alberta Deep Basin	09	Conventional	UprColr
Alberta Deep Basin	09	Conventional	Mnvl;Jur
Alberta Deep Basin	09	Conventional	Tri
Alberta Deep Basin	09	Conventional	UprDvn
Alberta Deep Basin	09	Tight	UprColr
Alberta Deep Basin	09	Tight	Colr
Alberta Deep Basin	09	Tight	Mnvl;Jur
Alberta Deep Basin	09	Tight	Tri
Northeast Alberta	10	Conventional	Mnvl;UprDvn
Peace River	11	Conventional	UprColr
Peace River	11	Conventional	Colr;UprMnvl
Peace River	11	Conventional	MdlMnvl;LwrMnvl
Peace River	11	Conventional	UprTri
Peace River	11	Conventional	LwrTri
Peace River	11	Conventional	Miss
Peace River	11	Conventional	UprDvn;MdlDvn
Peace River	11	Tight	UprColr
Peace River	11	Tight	MdlMnvl;LwrMnvl
Peace River	11	Tight	UprTri
Peace River	11	Tight	LwrTri
Peace River	11	Tight	Tri
Peace River	11	Tight	Miss
Northwest Alberta	12	Conventional	Mnvl
Northwest Alberta	12	Conventional	Miss
Northwest Alberta	12	Conventional	UprDvn
Northwest Alberta	12	Conventional	MdlDvn
BC Deep Basin	13	Conventional	Colr
BC Deep Basin	13	Conventional	LwrTri
BC Deep Basin	13	Tight	Colr
BC Deep Basin	13	Tight	Mnvl

Area name	Area Number	Resource Type	Resource Group
BC Deep Basin	13	Tight	LwrTri
Fort St. John	14	Conventional	Mnvl
Fort St. John	14	Conventional	Tri
Fort St. John	14	Conventional	Perm;Miss
Fort St. John	14	Conventional	UprDvn;MdlDvn
Fort St. John	14	Tight	Tri
Northeast BC	15	Conventional	LwrMnvl
Northeast BC	15	Conventional	Perm;Miss
Northeast BC	15	Conventional	UprDvn;MdlDvn
Northeast BC	15	Tight	UprDvn
Northeast BC	15	Shale	MdlDvn
BC Foothills	16	Conventional	Colr;Mnvl
BC Foothills	16	Conventional	Tri;Perm;Miss
BC Foothills	16	Tight	LwrTri
BC Foothills	16	Tight	Tri
Southwest Saskatchewan	17	Tight	UprColr
West Saskatchewan	18	Conventional	Colr
West Saskatchewan	18	Conventional	MdlMnvl;LwrMnvl;Miss
East Saskatchewan	19	Conventional	Solution Gas

Table A3.3 - Decline Parameters for Groupings of Existing Gas Connections

Resource Grouping - Gas - Alberta Coalbed Methane - Horseshoe Canyon						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2005	173.71	0.14	0.12	25	0.10	60
2006	229.90	0.14	0.12	25	0.10	60
2007	152.19	0.14	0.12	25	0.10	60
2008	116.60	0.14	0.12	25	0.10	60
2009	92.12	0.14	0.12	25	0.10	60
2010	48.27	0.14	0.12	25	0.10	60

Resource Grouping - Gas - Alberta Coalbed Methane - Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2006	45.22	0.16	0.14	25	0.12	60
2007	31.48	0.16	0.14	25	0.12	60
2008	38.56	0.14	0.12	25	0.10	60
2009	8.33	0.14	0.12	25	0.10	60
2010	4.75	0.14	0.12	25	0.10	60

Resource Grouping - Gas - Alberta Coalbed Methane - Other						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2005	14.40	0.10	0.08	25	0.05	60
2006	16.07	0.10	0.08	25	0.05	60
2007	20.53	0.10	0.08	25	0.05	60
2008	22.30	0.10	0.08	25	0.05	60
2009	7.21	0.10	0.08	25	0.05	60
2010	3.53	0.10	0.08	25	0.05	60

Resource Grouping - Gas - Southern Alberta - Conventional - Tertiary, Upper Cretaceous, Upper Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	12.19	0.16	0.14	25	0.12	60
2003	18.55	0.16	0.14	25	0.12	60
2004	35.07	0.16	0.14	25	0.12	60
2005	25.32	0.16	0.14	25	0.12	60
2006	32.01	0.16	0.14	25	0.12	60
2007	34.80	0.16	0.14	25	0.12	60
2008	29.45	0.16	0.14	25	0.12	60
2009	15.32	0.16	0.14	25	0.12	60
2010	31.54	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southern Alberta - Conventional - Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	11.04	0.16	0.14	25	0.12	60
2003	11.47	0.16	0.14	25	0.12	60
2004	15.96	0.16	0.14	25	0.12	60
2005	9.07	0.16	0.14	25	0.12	60
2006	7.10	0.16	0.14	25	0.12	60
2007	17.02	0.16	0.14	25	0.12	60
2008	19.24	0.16	0.14	25	0.12	60
2009	8.12	0.16	0.14	25	0.12	60
2010	4.26	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southern Alberta - Conventional - Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	26.52	0.16	0.14	25	0.12	60
2003	34.67	0.16	0.14	25	0.12	60
2004	36.06	0.16	0.14	25	0.12	60
2005	24.43	0.16	0.14	25	0.12	60
2006	30.06	0.16	0.14	25	0.12	60
2007	42.53	0.16	0.14	25	0.12	60
2008	49.90	0.16	0.14	25	0.12	60
2009	27.07	0.16	0.14	25	0.12	60
2010	28.68	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southern Alberta - Tight - Upper Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	126.70	0.16	0.14	25	0.12	60
2003	182.08	0.16	0.14	25	0.12	60
2004	258.02	0.16	0.14	25	0.12	60
2005	183.92	0.16	0.14	25	0.12	60
2006	174.99	0.16	0.14	25	0.12	60
2007	185.42	0.16	0.14	25	0.12	60
2008	171.17	0.16	0.14	25	0.12	60
2009	113.86	0.16	0.14	25	0.12	60
2010	101.24	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Conventional - Tertiary, Upper Cretaceous, Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	14.72	0.16	0.14	25	0.12	60
2003	19.22	0.16	0.14	25	0.12	60
2004	13.75	0.16	0.14	25	0.12	60
2005	19.12	0.16	0.14	25	0.12	60
2006	16.58	0.16	0.14	25	0.12	60
2007	14.43	0.16	0.14	25	0.12	60
2008	16.16	0.16	0.14	25	0.12	60
2009	5.31	0.16	0.14	25	0.12	60
2010	9.72	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Conventional - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	3.25	0.16	0.14	25	0.12	60
2003	5.31	0.16	0.14	25	0.12	60
2004	1.81	0.16	0.14	25	0.12	60
2005	4.42	0.16	0.14	25	0.12	60
2006	3.08	0.16	0.14	25	0.12	60
2007	2.82	0.16	0.14	25	0.12	60
2008	2.24	0.16	0.14	25	0.12	60
2009	0.65	0.16	0.14	25	0.12	60
2010	1.02	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Conventional - Middle Mannville, Lower Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	6.99	0.16	0.14	25	0.12	60
2003	4.30	0.16	0.14	25	0.12	60
2004	8.27	0.16	0.14	25	0.12	60
2005	7.92	0.16	0.14	25	0.12	60
2006	4.50	0.16	0.14	25	0.12	60
2007	8.39	0.16	0.14	25	0.12	60
2008	12.96	0.16	0.14	25	0.12	60
2009	11.47	0.16	0.14	25	0.12	60
2010	10.94	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Conventional - Jurassic, Mississippian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	2.90	0.16	0.14	25	0.12	60
2003	5.12	0.16	0.14	25	0.12	60
2004	4.63	0.16	0.14	25	0.12	60
2005	2.03	0.16	0.14	25	0.12	60
2006	0.20	0.16	0.14	25	0.12	60
2007	2.44	0.16	0.14	25	0.12	60
2008	2.54	0.16	0.14	25	0.12	60
2009	5.09	0.16	0.14	25	0.12	60
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Conventional - Upper Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	4.62	0.20	0.16	25	0.12	60
2003	29.12	0.20	0.16	25	0.12	60
2004	11.12	0.20	0.16	25	0.12	60
2005	0.81	0.20	0.16	25	0.12	60
2006	0.00	0.00	0.00	0	0.00	0
2007	3.12	0.20	0.16	25	0.12	60
2008	1.21	0.25	0.16	25	0.12	60
2009	0.00	0.00	0.00	0	0.00	0
2010	3.17	0.20	0.16	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Tight - Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	1.26	0.20	0.16	25	0.12	60
2003	2.39	0.20	0.16	25	0.12	60
2004	3.89	0.20	0.16	25	0.12	60
2005	5.10	0.20	0.16	25	0.12	60
2006	1.05	0.20	0.16	25	0.12	60
2007	2.05	0.20	0.16	25	0.12	60
2008	0.20	0.20	0.16	25	0.12	60
2009	0.48	0.20	0.16	25	0.12	60
2010	0.00	0.20	0.16	25	0.12	60

Resource Grouping - Gas - Southwest Alberta - Tight - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	1.54	0.20	0.16	25	0.12	60
2003	2.97	0.20	0.16	25	0.12	60
2004	2.01	0.20	0.16	25	0.12	60
2005	1.31	0.20	0.16	25	0.12	60
2006	0.35	0.20	0.16	25	0.12	60
2007	2.04	0.20	0.16	25	0.12	60
2008	0.10	0.20	0.16	25	0.12	60
2009	2.47	0.20	0.16	20	0.12	60
2010	0.00	0.20	0.16	20	0.12	60

Resource Grouping - Gas - Southwest Alberta - Tight - Lower Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	11.76	0.16	0.14	25	0.12	60
2003	15.12	0.16	0.14	25	0.12	60
2004	21.62	0.16	0.14	25	0.12	60
2005	13.39	0.16	0.14	25	0.12	60
2006	19.96	0.16	0.14	25	0.12	60
2007	15.16	0.16	0.14	25	0.12	60
2008	11.70	0.16	0.14	25	0.12	60
2009	7.29	0.16	0.14	25	0.12	60
2010	3.55	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southern Foothills - Conventional - Mississippian, Upper Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	50.10	0.14	0.13	25	0.12	60
2003	25.40	0.16	0.14	25	0.12	60
2004	65.59	0.16	0.14	25	0.12	60
2005	26.00	0.16	0.14	25	0.12	60
2006	74.42	0.16	0.14	25	0.12	60
2007	38.40	0.16	0.14	25	0.12	60
2008	24.44	0.16	0.14	25	0.12	60
2009	32.85	0.16	0.14	25	0.12	60
2010	0.01	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Eastern Alberta - Conventional - Upper Cretaceous, Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	1.87	0.16	0.14	25	0.12	60
2003	2.97	0.16	0.14	25	0.12	60
2004	2.90	0.16	0.14	25	0.12	60
2005	6.06	0.16	0.14	25	0.12	60
2006	12.37	0.16	0.14	25	0.12	60
2007	11.50	0.16	0.14	25	0.12	60
2008	18.02	0.30	0.22	18	0.11	40
2009	2.24	0.16	0.14	25	0.12	60
2010	3.39	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Eastern Alberta - Conventional - Colorado, Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	97.80	0.16	0.14	25	0.12	60
2003	88.69	0.16	0.14	25	0.12	60
2004	119.24	0.16	0.14	25	0.12	60
2005	144.29	0.16	0.14	25	0.12	60
2006	114.35	0.16	0.14	25	0.12	60
2007	94.62	0.16	0.14	25	0.12	60
2008	92.00	0.16	0.14	25	0.12	60
2009	50.07	0.16	0.14	25	0.12	60
2010	24.16	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Eastern Alberta - Tight - Upper Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	6.22	0.16	0.14	25	0.12	60
2003	5.83	0.16	0.14	25	0.12	60
2004	0.00	0.00	0.00	0	0.00	0
2005	5.84	0.16	0.14	25	0.12	60
2006	3.60	0.16	0.14	25	0.12	60
2007	1.34	0.16	0.14	25	0.12	60
2008	0.35	0.16	0.14	25	0.12	60
2009	1.23	0.16	0.14	25	0.12	60
2010	1.27	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Alberta - Conventional - Tertiary, Upper Cretaceous						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	16.86	0.16	0.14	25	0.12	60
2003	30.18	0.16	0.14	25	0.12	60
2004	47.82	0.16	0.14	25	0.12	60
2005	49.91	0.16	0.14	25	0.12	60
2006	49.07	0.16	0.14	25	0.12	60
2007	55.71	0.16	0.14	25	0.12	60
2008	43.24	0.16	0.14	25	0.12	60
2009	12.75	0.16	0.14	25	0.12	60
2010	10.79	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Alberta - Conventional - Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	6.22	0.16	0.14	25	0.12	60
2003	11.41	0.16	0.14	25	0.12	60
2004	12.65	0.16	0.14	25	0.12	60
2005	15.30	0.16	0.14	25	0.12	60
2006	13.40	0.16	0.14	25	0.12	60
2007	16.03	0.16	0.14	25	0.12	60
2008	7.81	0.16	0.14	25	0.12	60
2009	3.06	0.16	0.14	25	0.12	60
2010	3.01	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Alberta - Conventional - Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	91.65	0.16	0.14	25	0.12	60
2003	128.87	0.16	0.14	25	0.12	60
2004	133.25	0.16	0.14	25	0.12	60
2005	142.75	0.16	0.14	25	0.12	60
2006	186.87	0.16	0.14	25	0.12	60
2007	163.31	0.16	0.14	25	0.12	60
2008	158.62	0.16	0.14	25	0.12	60
2009	78.67	0.16	0.14	25	0.12	60
2010	48.63	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Alberta - Conventional - Mississippian, Upper Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	9.02	0.16	0.14	25	0.12	60
2003	25.14	0.16	0.14	25	0.12	60
2004	8.99	0.16	0.14	25	0.12	60
2005	14.39	0.16	0.14	25	0.12	60
2006	11.35	0.16	0.14	25	0.12	60
2007	15.86	0.16	0.14	25	0.12	60
2008	11.88	0.16	0.14	25	0.12	60
2009	3.93	0.16	0.14	25	0.12	60
2010	2.48	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Alberta - Tight - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	3.07	0.10	0.08	25	0.05	60
2003	8.47	0.10	0.08	25	0.05	60
2004	7.32	0.10	0.08	25	0.05	60
2005	11.01	0.10	0.08	25	0.05	60
2006	5.80	0.10	0.08	25	0.05	60
2007	2.23	0.10	0.08	25	0.05	60
2008	1.12	0.10	0.08	25	0.05	60
2009	2.60	0.10	0.08	25	0.05	60
2010	1.26	0.10	0.08	25	0.05	60

Resource Grouping - Gas - Central Alberta - Tight - Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2009 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	0.35	0.16	0.14	25	0.12	60
2003	2.47	0.16	0.14	25	0.12	60
2004	4.31	0.16	0.14	25	0.12	60
2005	3.47	0.16	0.14	25	0.12	60
2006	3.77	0.16	0.14	25	0.12	60
2007	3.73	0.16	0.14	25	0.12	60
2008	2.34	0.16	0.14	25	0.12	60
2009	2.25	0.16	0.14	25	0.12	60
2010	2.13	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Central Alberta - Conventional - Tertiary						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	5.83	0.14	0.12	25	0.10	60
2003	10.96	0.16	0.14	25	0.12	60
2004	21.19	0.16	0.14	25	0.12	60
2005	25.89	0.16	0.14	25	0.12	60
2006	26.48	0.16	0.14	25	0.12	60
2007	22.51	0.16	0.14	25	0.12	60
2008	22.27	0.16	0.14	25	0.12	60
2009	10.58	0.16	0.14	25	0.12	60
2010	17.20	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Central Alberta - Conventional - Upper Cretaceous, Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	9.13	0.16	0.14	25	0.12	60
2003	12.00	0.16	0.14	25	0.12	60
2004	16.27	0.16	0.14	25	0.12	60
2005	21.10	0.16	0.14	25	0.12	60
2006	28.19	0.16	0.14	25	0.12	60
2007	24.05	0.16	0.14	25	0.12	60
2008	24.48	0.16	0.14	25	0.12	60
2009	16.58	0.16	0.14	25	0.12	60
2010	17.27	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Central Alberta - Conventional - Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	2.43	0.10	0.08	25	0.05	60
2003	2.55	0.10	0.08	25	0.05	60
2004	2.95	0.10	0.08	25	0.05	60
2005	7.75	0.10	0.08	25	0.05	60
2006	0.89	0.10	0.08	25	0.05	60
2007	1.91	0.10	0.08	25	0.05	60
2008	8.28	0.10	0.08	25	0.05	60
2009	0.12	0.10	0.08	25	0.05	60
2010	3.37	0.10	0.08	25	0.05	60

Resource Grouping - Gas - West Central Alberta - Conventional - Lower Mannville, Jurassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	22.74	0.12	0.10	25	0.08	60
2003	24.64	0.12	0.10	25	0.08	60
2004	30.95	0.12	0.10	25	0.08	60
2005	37.06	0.12	0.10	25	0.08	60
2006	44.83	0.12	0.10	25	0.08	60
2007	36.75	0.12	0.10	25	0.08	60
2008	38.61	0.12	0.10	25	0.08	60
2009	24.17	0.12	0.10	25	0.08	60
2010	14.93	0.12	0.10	25	0.08	60

Resource Grouping - Gas - West Central Alberta - Conventional - Missisippian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	50.77	0.16	0.14	25	0.12	60
2003	33.70	0.16	0.14	25	0.12	60
2004	41.52	0.16	0.14	25	0.12	60
2005	38.07	0.16	0.14	25	0.12	60
2006	42.58	0.16	0.14	25	0.12	60
2007	50.90	0.16	0.14	25	0.12	60
2008	15.08	0.16	0.14	25	0.12	60
2009	27.58	0.16	0.14	25	0.12	60
2010	19.87	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Central Alberta - Conventional - Upper Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	18.52	0.16	0.14	25	0.12	60
2003	25.29	0.16	0.14	25	0.12	60
2004	38.88	0.16	0.14	25	0.12	60
2005	29.13	0.16	0.14	25	0.12	60
2006	4.11	0.16	0.14	25	0.12	60
2007	41.83	0.16	0.14	25	0.12	60
2008	1.51	0.16	0.14	25	0.12	60
2009	3.99	0.16	0.14	25	0.12	60
2010	2.25	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Central Alberta - Tight - Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	0.76	0.12	0.10	25	0.08	60
2003	3.06	0.12	0.10	25	0.08	60
2004	10.77	0.12	0.10	25	0.08	60
2005	11.05	0.12	0.10	25	0.08	60
2006	22.09	0.12	0.10	25	0.08	60
2007	7.12	0.12	0.10	25	0.08	60
2008	12.33	0.12	0.10	25	0.08	60
2009	1.17	0.12	0.10	25	0.08	60
2010	8.18	0.12	0.10	25	0.08	60

Resource Grouping - Gas - West Central Alberta - Tight - Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	53.87	0.16	0.14	25	0.12	60
2003	66.64	0.16	0.14	25	0.12	60
2004	88.53	0.16	0.14	25	0.12	60
2005	92.16	0.16	0.14	25	0.12	60
2006	118.46	0.16	0.14	25	0.12	60
2007	102.34	0.16	0.14	25	0.12	60
2008	124.06	0.16	0.14	25	0.12	60
2009	87.93	0.16	0.14	25	0.12	60
2010	59.75	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Conventional - Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	28.19	0.16	0.14	25	0.12	60
2003	10.28	0.16	0.14	25	0.12	60
2004	25.73	0.16	0.14	25	0.12	60
2005	15.32	0.16	0.14	25	0.12	60
2006	13.62	0.16	0.14	25	0.12	60
2007	13.35	0.16	0.14	25	0.12	60
2008	26.53	0.16	0.14	25	0.12	60
2009	6.28	0.16	0.14	25	0.12	60
2010	3.07	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Conventional - Colorado, Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	39.25	0.16	0.14	25	0.12	60
2003	36.89	0.16	0.14	25	0.12	60
2004	42.01	0.16	0.14	25	0.12	60
2005	11.97	0.16	0.14	25	0.12	60
2006	18.76	0.16	0.14	25	0.12	60
2007	16.61	0.16	0.14	25	0.12	60
2008	32.73	0.16	0.14	25	0.12	60
2009	19.67	0.16	0.14	25	0.12	60
2010	16.98	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Conventional - Jurassic, Triassic, Permian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	9.75	0.16	0.14	25	0.10	60
2003	22.47	0.16	0.14	25	0.12	60
2004	18.10	0.16	0.14	25	0.12	60
2005	5.41	0.16	0.14	25	0.12	60
2006	26.31	0.16	0.14	25	0.12	60
2007	37.89	0.16	0.14	25	0.12	60
2008	9.86	0.16	0.14	24	0.12	60
2009	24.08	0.16	0.14	25	0.12	60
2010	10.21	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Conventional - Mississippian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	129.06	0.14	0.12	25	0.10	60
2003	133.12	0.14	0.12	25	0.10	60
2004	78.61	0.14	0.12	25	0.10	60
2005	41.88	0.14	0.12	25	0.10	60
2006	31.76	0.14	0.12	25	0.12	60
2007	32.44	0.14	0.12	25	0.10	60
2008	51.10	0.14	0.12	25	0.10	60
2009	29.96	0.14	0.12	25	0.10	60
2010	2.73	0.14	0.12	25	0.10	60

Resource Grouping - Gas - Central Foothills - Conventional - Upper Devonian, Middle Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	40.63	0.16	0.14	25	0.12	60
2003	68.79	0.16	0.14	25	0.12	60
2004	31.29	0.16	0.14	25	0.12	60
2005	113.51	0.16	0.14	25	0.12	60
2006	8.12	0.16	0.14	25	0.12	60
2007	5.60	0.16	0.14	25	0.12	60
2008	5.55	0.16	0.14	25	0.12	60
2009	2.28	0.16	0.14	25	0.12	60
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Tight - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2003	0.34	0.16	0.14	25	0.12	60
2004	2.54	0.16	0.14	25	0.12	60
2005	3.05	0.16	0.14	25	0.12	60
2006	0.56	0.16	0.14	25	0.12	60
2007	3.33	0.16	0.14	25	0.12	60
2008	0.66	0.16	0.14	25	0.12	60
2009	2.13	0.16	0.14	25	0.12	60
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Tight - Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2003	1.67	0.16	0.14	25	0.12	60
2004	0.54	0.16	0.14	25	0.12	60
2005	0.46	0.16	0.14	25	0.12	60
2006	1.77	0.16	0.14	25	0.12	60
2007	1.55	0.16	0.14	25	0.12	60
2008	0.20	0.16	0.14	25	0.12	60
2009	0.00	0.16	0.14	25	0.12	60
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Central Foothills - Tight - Jurassic						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2007	9.02	0.16	0.14	25	0.12	60
2008	22.58	0.16	0.14	25	0.12	60
2009	6.09	0.16	0.14	25	0.12	60
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Kaybob - Conventional - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	3.69	0.16	0.14	25	0.12	60
2003	4.44	0.16	0.14	25	0.12	60
2004	5.65	0.16	0.14	25	0.12	60
2005	10.96	0.16	0.14	25	0.12	60
2006	13.74	0.16	0.14	25	0.12	60
2007	9.45	0.16	0.14	25	0.12	60
2008	5.43	0.16	0.14	25	0.12	60
2009	5.63	0.16	0.14	25	0.12	60
2010	5.10	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Kaybob - Conventional - Mannville, Jurassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	9.95	0.16	0.14	25	0.12	60
2003	18.96	0.16	0.14	25	0.12	60
2004	13.47	0.16	0.14	25	0.12	60
2005	28.72	0.16	0.14	25	0.12	60
2006	33.81	0.16	0.14	25	0.12	60
2007	31.98	0.16	0.14	25	0.12	60
2008	45.72	0.16	0.14	25	0.12	60
2009	34.69	0.16	0.14	25	0.12	60
2010	15.11	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Kaybob - Conventional - Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2009 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	18.56	0.16	0.14	25	0.12	60
2003	17.52	0.16	0.14	25	0.12	60
2004	8.48	0.16	0.14	25	0.12	60
2005	19.34	0.16	0.14	25	0.12	60
2006	11.43	0.16	0.14	25	0.12	60
2007	10.82	0.16	0.14	25	0.12	60
2008	13.73	0.16	0.14	25	0.12	60
2009	15.36	0.16	0.14	25	0.12	60
2010	2.27	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Kaybob - Conventional - Upper Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2003	10.77	0.16	0.10	25	0.05	60
2004	0.03	0.16	0.14	25	0.12	60
2005	0.13	0.16	0.14	25	0.12	60
2006	3.31	0.16	0.14	25	0.12	60
2007	4.64	0.16	0.14	25	0.12	60
2008	4.38	0.16	0.14	25	0.12	60
2009	9.75	0.16	0.14	25	0.12	60
2010	24.05	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Kaybob - Tight - Colorado, Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	22.19	0.16	0.14	25	0.12	60
2003	30.54	0.16	0.14	25	0.12	60
2004	45.60	0.16	0.14	25	0.12	60
2005	35.36	0.16	0.14	25	0.12	60
2006	69.78	0.16	0.14	25	0.12	60
2007	49.75	0.16	0.14	25	0.12	60
2008	49.01	0.16	0.14	25	0.12	60
2009	58.59	0.16	0.14	25	0.12	60
2010	45.67	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Kaybob - Tight - Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	8.86	0.10	0.08	25	0.05	60
2003	7.54	0.10	0.08	25	0.05	60
2004	7.95	0.10	0.08	25	0.05	60
2005	11.26	0.10	0.08	25	0.05	60
2006	12.40	0.10	0.08	25	0.05	60
2007	17.32	0.10	0.08	25	0.05	60
2008	10.27	0.10	0.08	25	0.05	60
2009	19.33	0.10	0.08	25	0.05	60
2010	28.88	0.10	0.08	25	0.05	60

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Upper Cretaceous						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	8.24	0.10	0.08	25	0.05	60
2003	10.96	0.10	0.08	25	0.05	60
2004	7.60	0.10	0.08	25	0.05	60
2005	8.43	0.10	0.08	25	0.05	60
2006	4.14	0.10	0.08	25	0.05	60
2007	3.46	0.10	0.08	25	0.05	60
2008	4.31	0.10	0.08	25	0.05	45
2009	5.48	0.10	0.08	25	0.05	45
2010	4.61	0.10	0.08	25	0.05	45

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Upper Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 20010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	13.06	0.12	0.10	25	0.08	60
2003	13.48	0.12	0.10	25	0.08	60
2004	14.54	0.12	0.10	25	0.08	60
2005	14.34	0.12	0.10	25	0.08	60
2006	19.51	0.12	0.10	25	0.08	60
2007	9.68	0.12	0.10	25	0.08	60
2008	9.35	0.12	0.10	25	0.08	45
2009	2.70	0.12	0.10	25	0.08	45
2010	10.51	0.12	0.10	25	0.08	45

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Mannville, Jurassic						
Connection Year	**Group Production Rate as of Dec. 31, 2009 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	0.49	0.10	0.08	25	0.05	60
2003	1.59	0.10	0.08	25	0.05	60
2004	3.76	0.10	0.08	25	0.05	60
2005	3.02	0.10	0.08	25	0.05	60
2006	5.19	0.10	0.08	25	0.05	60
2007	4.19	0.10	0.08	25	0.05	60
2008	7.67	0.10	0.08	25	0.05	45
2009	4.46	0.10	0.08	25	0.05	45
2010	11.32	0.10	0.08	25	0.05	45

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	8.97	0.10	0.08	25	0.05	60
2003	10.17	0.10	0.08	25	0.05	60
2004	12.34	0.10	0.08	25	0.05	60
2005	11.12	0.10	0.08	25	0.05	60
2006	9.79	0.10	0.08	25	0.05	60
2007	3.87	0.10	0.08	25	0.05	60
2008	2.83	0.10	0.08	25	0.05	45
2009	6.04	0.10	0.08	20	0.05	40
2010	9.98	0.10	0.08	25	0.05	60

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Upper Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	12.54	0.16	0.14	25	0.12	60
2003	4.13	0.16	0.14	25	0.12	60
2004	16.19	0.16	0.14	25	0.12	60
2005	6.12	0.16	0.14	25	0.12	60
2006	0.32	0.16	0.14	25	0.12	60
2007	15.31	0.16	0.14	25	0.12	60
2008	0.38	0.16	0.14	25	0.12	60
2009	4.88	0.16	0.14	25	0.12	60
2010	3.54	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Alberta Deep Basin - Tight - Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	31.32	0.16	0.14	25	0.12	60
2003	26.27	0.16	0.14	25	0.12	60
2004	58.70	0.16	0.14	25	0.12	60
2005	64.79	0.16	0.14	25	0.12	60
2006	66.36	0.16	0.14	25	0.12	60
2007	48.05	0.16	0.14	25	0.12	60
2008	36.02	0.16	0.14	25	0.12	60
2009	40.75	0.16	0.14	25	0.12	60
2010	50.02	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Alberta Deep Basin - Tight - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	11.31	0.14	0.12	25	0.10	60
2003	16.84	0.14	0.12	25	0.10	60
2004	11.28	0.14	0.12	25	0.10	60
2005	9.59	0.14	0.12	25	0.10	60
2006	13.94	0.14	0.12	25	0.10	60
2007	19.99	0.14	0.12	25	0.10	60
2008	21.77	0.14	0.12	25	0.10	60
2009	8.46	0.14	0.12	25	0.10	60
2010	10.59	0.14	0.12	25	0.10	60

Resource Grouping - Gas - Alberta Deep Basin - Tight - Mannville, Jurassic						
Connection Year	Group Production Rate as of Dec. 31, 20010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	59.69	0.14	0.12	25	0.10	60
2003	111.76	0.14	0.12	25	0.10	60
2004	169.36	0.14	0.12	25	0.10	60
2005	211.42	0.14	0.12	25	0.10	60
2006	300.89	0.14	0.12	25	0.10	60
2007	259.13	0.14	0.12	25	0.10	60
2008	310.64	0.14	0.12	25	0.10	60
2009	223.56	0.14	0.12	25	0.10	60
2010	291.44	0.14	0.12	25	0.10	60

Resource Grouping - Gas - Alberta Deep Basin - Tight - Triassic						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	2.92	0.10	0.08	25	0.05	60
2003	3.50	0.10	0.08	25	0.05	60
2004	5.23	0.10	0.08	25	0.05	60
2005	9.30	0.10	0.08	25	0.05	60
2006	6.83	0.10	0.08	25	0.05	60
2007	1.91	0.10	0.08	25	0.05	60
2008	7.76	0.10	0.08	25	0.05	60
2009	16.68	0.10	0.08	25	0.05	60
2010	45.57	0.10	0.08	25	0.05	60

Resource Grouping - Gas - Northeast Alberta - Conventional - Mannville, Upper Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	108.92	0.20	0.18	25	0.16	60
2003	111.77	0.20	0.18	25	0.16	60
2004	109.84	0.20	0.18	25	0.16	60
2005	84.18	0.20	0.18	25	0.16	60
2006	92.08	0.20	0.18	25	0.16	60
2007	86.98	0.20	0.18	25	0.16	60
2008	58.53	0.20	0.18	25	0.16	60
2009	44.71	0.20	0.18	25	0.16	60
2010	32.83	0.20	0.18	25	0.16	60

Resource Grouping - Gas - Peace River - Conventional - Upper Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	0.46	0.24	0.22	25	0.20	60
2003	3.25	0.24	0.22	25	0.20	60
2004	4.74	0.24	0.22	25	0.20	60
2005	8.33	0.24	0.22	25	0.20	60
2006	2.33	0.24	0.22	25	0.20	60
2007	3.75	0.16	0.14	25	0.12	60
2008	0.68	0.16	0.14	25	0.12	60
2009	0.48	0.16	0.14	25	0.12	60
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Peace River - Conventional - Colorado, Upper Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	0.94	0.22	0.20	25	0.18	60
2003	2.46	0.22	0.20	25	0.18	60
2004	4.83	0.22	0.20	25	0.18	60
2005	10.79	0.22	0.20	25	0.18	60
2006	6.75	0.22	0.20	25	0.18	60
2007	7.42	0.22	0.20	25	0.18	60
2008	5.26	0.22	0.20	25	0.18	60
2009	3.47	0.22	0.20	25	0.18	60
2010	11.50	0.22	0.20	25	0.18	60

Resource Grouping - Gas - Peace River - Conventional - Middle Mannville, Lower Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	5.64	0.16	0.14	25	0.12	60
2003	7.27	0.16	0.14	25	0.12	60
2004	8.06	0.16	0.14	25	0.12	60
2005	8.57	0.16	0.14	25	0.12	60
2006	17.14	0.16	0.14	25	0.12	60
2007	12.10	0.16	0.14	25	0.12	60
2008	15.19	0.16	0.14	25	0.12	60
2009	7.48	0.16	0.14	25	0.12	60
2010	10.31	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Peace River - Conventional - Upper Triassic						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	2.98	0.20	0.16	25	0.12	60
2003	7.35	0.16	0.14	25	0.12	60
2004	6.39	0.16	0.14	25	0.12	60
2005	3.31	0.20	0.18	25	0.16	60
2006	9.46	0.20	0.18	25	0.16	60
2007	4.74	0.20	0.18	25	0.16	60
2008	4.18	0.20	0.18	25	0.16	60
2009	6.83	0.20	0.18	25	0.16	60
2010	4.11	0.20	0.18	25	0.16	60

Resource Grouping - Gas - Peace River - Conventional - Lower Triassic						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	4.22	0.16	0.14	25	0.12	60
2003	3.71	0.16	0.14	25	0.12	60
2004	5.76	0.16	0.14	25	0.12	60
2005	4.71	0.16	0.14	25	0.12	60
2006	16.88	0.16	0.14	25	0.12	60
2007	9.36	0.16	0.14	25	0.12	60
2008	17.93	0.16	0.14	25	0.12	60
2009	29.33	0.16	0.14	25	0.12	60
2010	47.74	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Peace River - Conventional - Mississippian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	8.55	0.16	0.14	25	0.12	60
2003	20.70	0.16	0.14	25	0.12	60
2004	37.52	0.16	0.14	25	0.12	60
2005	35.75	0.16	0.14	25	0.12	60
2006	19.37	0.16	0.14	25	0.12	60
2007	10.52	0.16	0.14	25	0.12	60
2008	32.72	0.16	0.14	25	0.12	60
2009	12.16	0.16	0.14	25	0.12	60
2010	12.28	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Peace River - Conventional - Upper Devonian, Middle Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	5.79	0.16	0.14	25	0.12	60
2003	1.22	0.16	0.14	25	0.12	60
2004	3.07	0.16	0.14	25	0.12	60
2005	2.95	0.16	0.14	25	0.12	60
2006	1.61	0.16	0.14	25	0.12	60
2007	0.88	0.16	0.14	25	0.12	60
2008	0.20	0.16	0.14	25	0.12	60
2009	0.53	0.16	0.14	25	0.12	60
2010	0.24	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Peace River - Tight - Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	0.63	0.16	0.14	25	0.12	60
2003	0.43	0.16	0.14	25	0.12	60
2004	2.47	0.16	0.14	25	0.12	60
2005	3.07	0.16	0.14	25	0.12	60
2006	1.93	0.16	0.14	25	0.12	60
2007	2.18	0.16	0.14	25	0.12	60
2008	8.17	0.16	0.14	25	0.12	60
2009	3.72	0.16	0.14	25	0.12	60
2010	37.57	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Peace River - Tight - Lower Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	7.52	0.16	0.14	25	0.12	60
2003	4.64	0.16	0.14	25	0.12	60
2004	3.53	0.16	0.14	25	0.12	60
2005	5.72	0.16	0.14	25	0.12	60
2006	11.40	0.16	0.14	25	0.12	60
2007	10.68	0.16	0.14	25	0.12	60
2008	23.54	0.16	0.14	25	0.12	60
2009	31.04	0.16	0.14	25	0.12	60
2010	41.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northwest Alberta - Conventional - Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	26.49	0.16	0.14	25	0.12	60
2003	31.15	0.16	0.14	25	0.12	60
2004	34.85	0.16	0.14	25	0.12	60
2005	28.92	0.16	0.14	25	0.12	60
2006	35.41	0.16	0.14	25	0.12	60
2007	15.51	0.16	0.14	25	0.12	60
2008	28.86	0.16	0.14	25	0.12	60
2009	6.98	0.16	0.14	25	0.12	60
2010	6.02	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northwest Alberta - Conventional - Mississippian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	13.18	0.16	0.14	25	0.12	60
2003	10.26	0.16	0.14	25	0.12	60
2004	9.92	0.16	0.14	25	0.12	60
2005	17.36	0.16	0.14	25	0.12	60
2006	13.36	0.16	0.14	25	0.12	60
2007	6.04	0.16	0.14	25	0.12	60
2008	11.40	0.16	0.14	25	0.12	60
2009	1.48	0.16	0.14	25	0.12	60
2010	1.02	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northwest Alberta - Conventional - Upper Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	21.72	0.16	0.14	25	0.12	60
2003	22.10	0.16	0.14	25	0.12	60
2004	20.03	0.16	0.14	25	0.12	60
2005	8.02	0.16	0.14	25	0.12	60
2006	15.63	0.16	0.14	25	0.12	60
2007	6.47	0.16	0.14	25	0.12	60
2008	4.63	0.16	0.14	25	0.12	60
2009	5.04	0.16	0.14	25	0.12	60
2010	2.22	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northwest Alberta - Conventional - Middle Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	1.75	0.22	0.20	25	0.18	60
2003	2.52	0.22	0.20	25	0.18	60
2004	3.62	0.22	0.20	25	0.18	60
2005	3.40	0.22	0.20	25	0.18	60
2006	2.38	0.22	0.20	25	0.18	60
2007	0.91	0.22	0.20	25	0.18	60
2008	5.42	0.22	0.20	25	0.18	60
2009	6.89	0.22	0.20	25	0.18	60
2010	1.64	0.22	0.20	25	0.18	60

Resource Grouping - Gas - BC Deep Basin - Conventional - Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	3.71	0.16	0.14	25	0.12	60
2003	2.78	0.16	0.14	25	0.12	60
2004	27.26	0.16	0.14	25	0.12	60
2005	11.72	0.16	0.14	25	0.12	60
2006	0.53	0.16	0.14	25	0.12	60
2007	0.10	0.16	0.14	25	0.12	60
2008	0.26	0.16	0.14	25	0.12	60
2009	0.46	0.16	0.14	25	0.12	60
2010	0.46	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Deep Basin - Conventional - Lower Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2004	0.63	0.16	0.14	25	0.12	60
2005	15.90	0.16	0.14	25	0.12	60
2006	5.34	0.16	0.14	25	0.12	60
2007	18.42	0.16	0.14	25	0.12	60
2008	10.70	0.16	0.14	25	0.12	60
2009	30.46	0.16	0.14	25	0.12	60
2010	36.10	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Deep Basin - Tight - Colorado						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	10.14	0.10	0.08	25	0.05	60
2003	4.50	0.10	0.08	25	0.05	60
2004	1.69	0.10	0.08	25	0.05	60
2005	1.14	0.10	0.08	25	0.05	60
2006	4.34	0.10	0.08	25	0.05	60
2007	1.30	0.10	0.08	25	0.05	60
2008	11.31	0.10	0.08	25	0.05	60
2009	3.47	0.10	0.08	25	0.05	60
2010	0.01	0.10	0.08	25	0.05	60

Resource Grouping - Gas - BC Deep Basin - Tight - Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	0.66	0.16	0.14	25	0.12	60
2003	24.11	0.16	0.14	25	0.12	60
2004	27.50	0.16	0.14	25	0.12	60
2005	30.41	0.16	0.14	25	0.12	60
2006	91.80	0.16	0.14	25	0.12	60
2007	73.79	0.16	0.14	25	0.12	60
2008	144.96	0.16	0.14	25	0.12	60
2009	57.28	0.16	0.14	25	0.12	60
2010	59.22	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Deep Basin - Tight - Lower Triassic						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2006	6.98	0.16	0.14	25	0.12	60
2007	6.13	0.16	0.14	25	0.12	60
2008	7.57	0.16	0.14	25	0.12	60
2009	10.82	0.16	0.14	25	0.12	60
2010	18.36	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Fort St John - Conventional - Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	50.65	0.22	0.20	25	0.18	60
2003	63.51	0.22	0.20	25	0.18	60
2004	197.98	0.22	0.20	25	0.18	60
2005	172.70	0.22	0.20	25	0.18	60
2006	180.92	0.22	0.20	25	0.18	60
2007	100.81	0.22	0.20	25	0.18	60
2008	161.12	0.22	0.20	25	0.18	60
2009	44.03	0.22	0.20	25	0.18	60
2010	13.36	0.22	0.20	25	0.18	60

Resource Grouping - Gas - Fort St John - Conventional - Triassic						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	64.28	0.16	0.14	25	0.12	60
2003	62.66	0.16	0.14	25	0.12	60
2004	95.88	0.16	0.14	25	0.12	60
2005	80.47	0.16	0.14	25	0.12	60
2006	118.72	0.16	0.14	25	0.12	60
2007	177.43	0.16	0.14	25	0.12	60
2008	138.30	0.16	0.14	25	0.12	60
2009	71.22	0.16	0.14	25	0.12	60
2010	29.26	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Fort St John - Conventional - Permian, Mississippian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	6.53	0.16	0.14	25	0.12	60
2003	8.90	0.16	0.14	25	0.12	60
2004	5.87	0.16	0.14	25	0.12	60
2005	5.81	0.16	0.14	25	0.12	60
2006	15.12	0.16	0.14	25	0.12	60
2007	18.49	0.16	0.14	25	0.12	60
2008	12.02	0.16	0.14	25	0.12	60
2009	9.24	0.16	0.14	25	0.12	60
2010	5.04	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Fort St John - Conventional - Upper Devonian, Middle Devonian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	12.09	0.24	0.22	25	0.20	60
2003	60.19	0.16	0.14	25	0.12	60
2004	12.92	0.14	0.12	25	0.10	60
2005	5.25	0.16	0.14	25	0.12	60
2006	6.12	0.16	0.14	25	0.12	60
2007	2.54	0.16	0.14	25	0.12	60
2008	0.00	0.00	0.00	0	0.00	0
2009	0.00	0.00	0.00	0	0.00	0
2010	0.70	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Fort St John - Tight - Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2006	20.67	0.16	0.14	25	0.12	60
2007	27.00	0.16	0.14	25	0.12	60
2008	35.93	0.16	0.14	25	0.12	60
2009	57.52	0.16	0.14	25	0.12	60
2010	92.28	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northeast BC - Conventional - Lower Mannville						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	0.00	0.00	0.00	0	0.00	0
2003	0.00	0.00	0.00	0	0.00	0
2004	0.00	0.00	0.00	0	0.00	0
2005	0.20	0.16	0.14	25	0.12	60
2006	0.05	0.16	0.14	25	0.12	60
2007	0.00	0.00	0.00	0	0.00	0
2008	0.00	0.00	0.00	0	0.00	0
2009	0.00	0.00	0.00	0	0.00	0
2010	0.00	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northeast BC - Conventional - Permian, Mississippian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	6.43	0.20	0.18	25	0.16	60
2003	3.15	0.16	0.14	25	0.12	60
2004	8.25	0.16	0.14	25	0.12	60
2005	15.76	0.16	0.14	25	0.12	60
2006	5.70	0.16	0.14	25	0.12	60
2007	8.10	0.10	0.08	25	0.05	60
2008	1.95	0.16	0.14	25	0.12	60
2009	1.54	0.16	0.14	25	0.12	60
2010	0.29	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northeast BC - Conventional - Upper Devonian, Middle Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	6.72	0.16	0.14	25	0.12	60
2003	72.66	0.16	0.14	25	0.12	60
2004	24.15	0.16	0.14	25	0.12	60
2005	148.51	0.16	0.14	25	0.12	60
2006	119.88	0.10	0.08	25	0.05	60
2007	0.80	0.16	0.14	25	0.12	60
2008	8.81	0.16	0.14	25	0.12	60
2009	1.38	0.16	0.14	25	0.12	60
2010	0.02	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northeast BC - Tight - Upper Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	30.25	0.16	0.14	25	0.12	60
2003	101.25	0.16	0.14	25	0.12	60
2004	130.29	0.16	0.14	25	0.12	60
2005	108.14	0.16	0.14	25	0.12	60
2006	76.60	0.16	0.14	25	0.12	60
2007	16.20	0.16	0.14	25	0.12	60
2008	25.60	0.16	0.14	25	0.12	60
2009	7.90	0.16	0.14	25	0.12	60
2010	24.88	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Northeast BC - Shale - Middle Devonian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2006	60.72	0.16	0.14	25	0.12	60
2007	86.22	0.16	0.14	25	0.12	60
2008	117.40	0.16	0.14	25	0.12	60
2009	68.67	0.16	0.14	25	0.12	60
2010	235.27	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Foothills - Conventional - Colorado, Mannville						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2004	11.01	0.16	0.14	25	0.12	60
2005	7.50	0.16	0.14	25	0.12	60
2006	5.16	0.16	0.14	25	0.12	60
2007	16.72	0.16	0.14	25	0.12	60
2008	17.94	0.16	0.14	25	0.12	60
2009	38.05	0.16	0.14	25	0.12	60
2010	56.76	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Foothills - Conventional - Triassic, Permian, Mississippian						
Connection Year	Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d	First Decline Rate	Second Decline Rate	Months to Second Decline Rate	Third Decline Rate	Months to Third Decline Rate
2002	7.04	0.16	0.14	25	0.12	60
2003	57.49	0.16	0.14	25	0.12	60
2004	59.41	0.16	0.14	25	0.12	60
2005	84.35	0.10	0.08	25	0.05	60
2006	181.03	0.14	0.12	25	0.10	60
2007	68.11	0.16	0.14	25	0.12	60
2008	117.76	0.16	0.14	25	0.12	60
2009	71.59	0.16	0.14	25	0.12	60
2010	7.29	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Foothills - Tight - Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	4.17	0.10	0.08	25	0.05	60
2003	9.37	0.16	0.14	25	0.12	60
2004	8.25	0.16	0.14	25	0.12	60
2005	3.30	0.16	0.14	25	0.12	60
2006	14.20	0.16	0.14	25	0.12	60
2007	11.97	0.16	0.14	25	0.12	60
2008	41.37	0.16	0.14	25	0.12	60
2009	26.80	0.16	0.14	25	0.12	60
2010	114.51	0.16	0.14	25	0.12	60

Resource Grouping - Gas - BC Foothills - Tight - Lower Triassic						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	1.97	0.10	0.08	25	0.05	60
2003	0.00	0.00	0.00	0	0.00	0
2004	4.10	0.10	0.08	25	0.05	60
2005	10.23	0.16	0.14	25	0.12	60
2006	0.00	0.00	0.00	0	0.00	0
2007	11.53	0.16	0.14	25	0.12	60
2008	0.00	0.00	0.00	0	0.00	0
2009	0.14	0.16	0.14	25	0.12	60
2010	4.80	0.16	0.14	25	0.12	60

Resource Grouping - Gas - Southwest Saskatchewan - Tight - Upper Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	57.87	0.16	0.14	25	0.12	60
2003	67.40	0.16	0.14	25	0.12	60
2004	62.12	0.16	0.14	25	0.12	60
2005	54.07	0.16	0.14	25	0.12	60
2006	55.25	0.16	0.14	25	0.12	60
2007	53.47	0.16	0.14	25	0.12	60
2008	57.86	0.16	0.14	25	0.12	60
2009	28.59	0.16	0.14	25	0.12	60
2010	13.09	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Saskatchewan - Conventional - Colorado						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	0.80	0.16	0.14	25	0.12	60
2003	4.26	0.16	0.14	25	0.12	60
2004	9.16	0.16	0.14	25	0.12	60
2005	10.53	0.16	0.14	25	0.12	60
2006	7.82	0.16	0.14	25	0.12	60
2007	5.63	0.16	0.14	25	0.12	60
2008	6.18	0.16	0.14	25	0.12	60
2009	4.64	0.16	0.14	25	0.12	60
2010	0.70	0.16	0.14	25	0.12	60

Resource Grouping - Gas - West Saskatchewan - Conventional - Middle Mannville, Lower Mannville, Mississippian						
Connection Year	**Group Production Rate as of Dec. 31, 2010 Mkt MMcf/d**	**First Decline Rate**	**Second Decline Rate**	**Months to Second Decline Rate**	**Third Decline Rate**	**Months to Third Decline Rate**
2002	9.01	0.16	0.14	25	0.12	60
2003	8.11	0.16	0.14	25	0.12	60
2004	10.47	0.16	0.14	25	0.12	60
2005	9.02	0.16	0.14	25	0.12	60
2006	13.05	0.16	0.14	25	0.12	60
2007	14.96	0.16	0.14	25	0.12	60
2008	7.83	0.16	0.14	25	0.12	60
2009	8.68	0.16	0.14	25	0.12	60
2010	4.83	0.16	0.14	25	0.12	60

A4 Decline Parameters for Groupings of Future Gas Connections[1]

Resource Grouping - Gas - Alberta Coalbed Methane - Mannville

Connection Year	Peak Production MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2007	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2008	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2009	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2010	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2011	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2012	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2013	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00
2014	0.38	0.01	0.40	15.00	0.20	30.00	0.15	50.00	0.10	100.00

Resource Grouping - Gas - Alberta Coalbed Methane - Horseshoe Canyon

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2005	0.09	0.25	0.16	7.00	0.17	20.00	0.12	45.00	0.10	90.00
2006	0.09	0.25	0.18	7.00	0.16	20.00	0.12	45.00	0.10	90.00
2007	0.10	0.50	0.20	7.00	0.16	20.00	0.12	45.00	0.10	90.00
2008	0.09	0.40	0.20	7.00	0.16	20.00	0.14	45.00	0.10	90.00
2009	0.08	0.45	0.30	7.00	0.20	20.00	0.14	45.00	0.10	90.00
2010	0.06	0.55	0.30	7.00	0.20	20.00	0.14	45.00	0.10	90.00
2011	0.06	0.45	0.30	7.00	0.16	20.00	0.14	45.00	0.10	90.00
2012	0.05	0.45	0.30	7.00	0.16	20.00	0.14	45.00	0.10	90.00
2013	0.04	0.45	0.30	7.00	0.16	20.00	0.14	45.00	0.10	90.00
2014	0.04	0.45	0.30	7.00	0.16	20.00	0.14	45.00	0.10	90.00

Resource Grouping - Gas - Alberta Coalbed Methane - Other

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2005	0.07	0.50	0.30	7.00	0.16	20.00	0.10	45.00	0.05	90.00
2006	0.08	0.80	0.30	7.00	0.16	20.00	0.10	45.00	0.05	90.00
2007	0.08	0.75	0.30	7.00	0.16	20.00	0.10	45.00	0.05	90.00
2008	0.07	0.50	0.20	7.00	0.16	20.00	0.10	45.00	0.05	90.00
2009	0.03	0.40	0.25	7.00	0.16	20.00	0.10	45.00	0.05	90.00
2010	0.03	0.45	0.30	7.00	0.20	20.00	0.10	45.00	0.05	90.00
2011	0.04	0.45	0.30	7.00	0.20	20.00	0.10	45.00	0.05	90.00
2012	0.04	0.45	0.30	7.00	0.20	20.00	0.10	45.00	0.05	90.00
2013	0.04	0.45	0.30	7.00	0.20	20.00	0.10	45.00	0.05	90.00
2014	0.04	0.45	0.30	7.00	0.20	20.00	0.10	45.00	0.05	90.00

Resource Grouping - Gas - Southern Alberta - Conventional - Tertiary, Upper Cretaceous, Upper Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.17	1.15	0.37	7.00	0.22	20.00	0.18	45.00	0.12	90.00
2003	0.08	0.40	0.20	15.00	0.18	30.00	0.16	55.00	0.12	90.00
2004	0.14	0.85	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2005	0.08	0.70	0.45	7.00	0.22	20.00	0.18	45.00	0.12	90.00
2006	0.08	0.85	0.40	7.00	0.24	20.00	0.16	45.00	0.12	90.00
2007	0.09	0.60	0.42	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.09	0.55	0.45	10.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.09	0.75	0.45	8.00	0.25	20.00	0.18	45.00	0.12	90.00
2010	0.12	0.75	0.40	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2011	0.10	0.75	0.40	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2012	0.10	0.75	0.40	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2013	0.10	0.75	0.40	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2014	0.10	0.75	0.40	7.00	0.25	20.00	0.18	45.00	0.12	90.00

1 Decline parameters by connection for existing wells connected between 2002 and 2010 are provided to indicate trends

Resource Grouping - Gas - Southern Alberta - Conventional - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.45	1.25	0.95	7.00	0.45	20.00	0.16	45.00	0.12	90.00
2003	0.24	1.15	0.85	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2004	0.26	1.15	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2005	0.23	0.85	0.60	10.00	0.50	20.00	0.25	45.00	0.12	90.00
2006	0.16	1.25	0.75	7.00	0.40	30.00	0.20	50.00	0.12	90.00
2007	0.13	0.85	0.70	10.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	0.10	0.75	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.13	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	0.16	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.20	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.24	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.30	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.37	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Southern Alberta - Conventional - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.55	0.95	0.65	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2003	0.34	0.50	0.45	7.00	0.42	20.00	0.20	45.00	0.12	90.00
2004	0.36	0.70	0.55	7.00	0.38	20.00	0.20	45.00	0.12	90.00
2005	0.31	0.55	0.65	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2006	0.24	0.53	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	0.22	0.40	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	0.36	0.70	0.50	10.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	0.27	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.26	0.75	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.24	0.75	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.22	0.75	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.21	0.75	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.20	0.75	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Southern Alberta - Tight - Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.09	0.80	0.35	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2003	0.08	0.60	0.35	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2004	0.09	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2005	0.08	0.80	0.35	7.00	0.22	20.00	0.12	45.00	0.12	90.00
2006	0.09	0.85	0.38	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	0.09	0.70	0.45	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2008	0.08	0.80	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.08	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.10	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	0.10	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	0.10	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	0.11	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	0.11	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Conventional - Tertiary, Upper Cretaceous, Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.25	0.83	0.52	10.00	0.30	18.00	0.14	42.00	0.99	83.00
2003	0.20	0.90	0.40	7.00	0.22	20.00	0.16	45.00	0.99	68.00
2004	0.20	0.99	0.95	5.00	0.30	15.00	0.16	45.00	0.12	90.00
2005	0.17	1.20	0.40	8.00	0.35	20.00	0.16	45.00	0.12	90.00
2006	0.14	0.80	0.42	11.00	0.26	20.00	0.16	38.00	0.12	90.00
2007	0.15	1.30	0.80	7.00	0.22	12.00	0.16	24.00	5.00	30.00
2008	0.13	0.65	0.60	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2009	0.11	0.20	0.48	7.00	0.49	20.00	0.16	45.00	0.12	90.00
2010	0.08	0.80	0.40	7.00	0.25	20.00	0.16	42.00	0.12	65.00
2011	0.08	0.80	0.40	7.00	0.25	20.00	0.16	42.00	0.12	65.00
2012	0.08	0.80	0.40	7.00	0.25	20.00	0.16	42.00	0.12	65.00
2013	0.07	0.80	0.40	7.00	0.25	20.00	0.16	42.00	0.12	65.00
2014	0.07	0.80	0.40	7.00	0.25	20.00	0.16	42.00	0.12	65.00

Resource Grouping - Gas - Southwest Alberta - Conventional - Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.30	1.05	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2003	0.21	0.30	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2004	0.20	0.65	0.70	7.00	0.50	20.00	0.25	45.00	0.12	90.00
2005	0.13	0.95	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2006	0.24	1.25	0.75	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	0.24	1.45	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.28	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.13	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.13	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.18	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.18	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.18	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.18	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Conventional - Middle Mannville, Lower Mannville

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.78	1.05	0.50	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2003	0.65	0.20	0.25	7.00	0.65	20.00	0.33	45.00	0.12	90.00
2004	0.42	0.85	0.65	7.00	0.25	20.00	0.14	45.00	0.12	90.00
2005	0.61	1.15	0.75	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2006	0.43	0.85	0.80	7.00	0.45	20.00	0.27	45.00	0.12	90.00
2007	0.47	0.65	0.55	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2008	0.43	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.56	0.70	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.67	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.73	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.78	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.84	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.89	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Conventional - Jurassic, Mississippian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.77	0.65	0.90	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2003	0.48	0.75	0.70	7.00	0.20	20.00	0.12	45.00	0.12	90.00
2004	0.35	0.65	0.60	7.00	0.22	20.00	0.14	45.00	0.12	90.00
2005	0.53	1.35	0.83	7.00	0.27	20.00	0.14	45.00	0.12	90.00
2006	0.23	1.05	2.05	7.00	0.75	20.00	0.25	45.00	0.12	90.00
2007	0.34	1.05	0.78	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.82	1.05	0.95	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2009	1.01	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.91	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.91	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.91	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.91	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.91	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Conventional - Upper Devonian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.86	1.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2003	2.06	0.65	0.50	7.00	0.35	20.00	0.25	45.00	0.12	90.00
2004	1.20	0.65	0.20	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2005	0.10	0.30	0.20	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.55	0.75	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.26	1.25	0.80	7.00	0.40	20.00	0.16	45.00	0.12	90.00
2009	0.23	1.00	0.60	7.00	0.33	20.00	0.16	45.00	0.12	90.00
2010	0.20	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.17	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.15	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.13	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.12	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Tight - Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.17	1.25	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2003	0.10	0.85	0.40	7.00	0.22	20.00	0.14	45.00	0.12	90.00
2004	0.17	0.85	0.55	7.00	0.50	20.00	0.16	45.00	0.12	90.00
2005	0.11	1.65	0.40	7.00	0.27	20.00	0.16	45.00	0.12	90.00
2006	0.06	1.25	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	0.14	1.35	0.65	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2008	0.07	0.99	0.75	7.00	0.50	20.00	0.16	45.00	0.12	90.00
2009	0.27	1.25	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.17	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.17	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.17	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.17	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.17	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Tight - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.26	1.55	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2003	0.21	0.65	0.35	7.00	0.22	20.00	0.18	45.00	0.12	90.00
2004	0.34	1.10	0.50	7.00	0.45	20.00	0.16	45.00	0.12	90.00
2005	0.19	0.75	0.55	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2006	0.13	1.45	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	0.35	0.60	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.40	0.85	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	0.36	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.37	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.37	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.37	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.37	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.37	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Alberta - Tight - Lower Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.04	0.85	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2003	0.66	0.45	0.25	7.00	0.20	20.00	0.12	45.00	0.12	90.00
2004	0.59	0.35	0.20	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2005	0.72	0.95	0.45	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2006	1.00	0.75	0.45	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	0.64	0.75	0.45	7.00	0.28	20.00	0.16	45.00	0.12	90.00
2008	0.42	0.65	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.39	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.43	0.95	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.43	0.95	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.43	0.95	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.44	0.95	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.45	0.95	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southern Foothills - Conventional - Mississippian, Upper Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	3.93	0.10	0.12	7.00	0.12	20.00	0.12	45.00	0.12	90.00
2003	1.90	0.55	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2004	3.52	0.25	0.20	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2005	1.71	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	2.41	0.45	0.35	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	1.61	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2008	2.15	0.25	0.20	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2009	6.82	0.65	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	3.53	0.50	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	3.53	0.50	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	3.53	0.50	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	3.53	0.50	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	3.53	0.50	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Eastern Alberta - Conventional - Upper Cretaceous, Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.17	0.95	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2003	0.12	0.75	0.45	7.00	0.32	20.00	0.20	45.00	0.12	90.00
2004	0.11	1.05	0.35	7.00	0.30	20.00	0.25	45.00	0.12	90.00
2005	0.10	0.95	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2006	0.04	1.05	0.45	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2007	0.05	0.70	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.06	0.95	0.35	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.11	0.95	0.45	10.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.16	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.20	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.25	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.29	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.33	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Eastern Alberta - Conventional - Colorado, Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.36	0.75	0.45	7.00	0.34	20.00	0.20	45.00	0.12	90.00
2003	0.23	0.85	0.48	7.00	0.32	20.00	0.20	45.00	0.12	90.00
2004	0.20	0.95	0.50	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2005	0.19	0.90	0.50	7.00	0.32	20.00	0.16	45.00	0.12	90.00
2006	0.18	0.90	0.40	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	0.20	0.99	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	0.20	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.20	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.14	0.95	0.55	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2011	0.18	0.95	0.55	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2012	0.18	0.95	0.55	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2013	0.18	0.95	0.55	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2014	0.18	0.95	0.55	7.00	0.35	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Eastern Alberta - Tight - Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.05	0.95	0.32	7.00	0.18	20.00	0.12	45.00	0.12	90.00
2003	0.07	0.65	0.48	7.00	0.18	20.00	0.14	45.00	0.12	90.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.07	0.80	0.50	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	0.06	0.75	0.40	7.00	0.25	20.00	0.20	45.00	0.12	90.00
2007	0.04	1.05	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.06	0.75	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	0.06	1.75	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.05	1.40	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.05	1.40	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.05	1.40	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.05	1.40	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.05	1.40	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Alberta - Conventional - Tertiary, Upper Cretaceous										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.25	1.20	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2003	0.20	0.75	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2004	0.18	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2005	0.15	0.95	0.52	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.11	0.80	0.45	7.00	0.23	20.00	0.16	45.00	0.12	90.00
2007	0.15	0.65	0.42	7.00	0.28	20.00	0.16	45.00	0.12	90.00
2008	0.14	0.75	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.12	0.95	0.70	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2010	0.11	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.09	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.08	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.07	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.06	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Alberta - Conventional - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.25	0.95	0.65	7.00	0.25	20.00	0.14	45.00	0.12	90.00
2003	0.16	0.65	0.48	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2004	0.28	1.15	0.55	7.00	0.27	20.00	0.16	45.00	0.12	90.00
2005	0.22	1.15	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2006	0.11	0.70	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	0.15	0.50	0.30	7.00	0.23	20.00	0.16	45.00	0.12	90.00
2008	0.13	1.05	0.50	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2009	0.17	1.65	0.75	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2010	0.12	1.05	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.14	1.05	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.14	1.05	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.14	1.05	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.14	1.05	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Alberta - Conventional - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.46	0.85	0.50	7.00	0.30	20.00	0.25	45.00	0.12	90.00
2003	0.43	0.85	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2004	0.40	0.85	0.58	7.00	0.33	20.00	0.30	45.00	0.12	90.00
2005	0.33	0.85	0.53	7.00	0.35	20.00	0.25	45.00	0.12	90.00
2006	0.33	0.65	0.48	7.00	0.40	20.00	0.25	45.00	0.12	90.00
2007	0.32	0.85	0.55	7.00	0.35	20.00	0.25	45.00	0.12	90.00
2008	0.28	0.95	0.60	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2009	0.27	0.85	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.29	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2011	0.30	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2012	0.31	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2013	0.32	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2014	0.33	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Central Alberta - Conventional - Mississippian, Upper Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.46	0.85	0.50	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2003	0.79	0.85	0.40	7.00	0.26	20.00	0.23	45.00	0.12	90.00
2004	0.57	0.40	0.30	7.00	0.50	20.00	0.40	45.00	0.12	90.00
2005	0.42	1.15	0.65	7.00	0.25	20.00	0.20	45.00	0.12	90.00
2006	0.27	1.25	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	0.39	1.05	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.30	0.85	0.55	7.00	0.30	25.00	0.16	50.00	0.12	90.00
2009	0.18	0.95	0.75	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	0.10	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.08	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.07	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.06	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.05	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Alberta - Tight - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.31	1.15	0.40	7.00	0.16	20.00	0.17	45.00	0.05	90.00
2003	0.27	0.65	0.40	7.00	0.18	20.00	0.14	45.00	0.05	90.00
2004	0.33	1.15	0.60	7.00	0.22	20.00	0.14	45.00	0.05	90.00
2005	0.31	1.15	0.40	7.00	0.20	20.00	0.07	45.00	0.05	90.00
2006	0.20	0.65	0.40	7.00	0.22	20.00	0.12	45.00	0.05	90.00
2007	0.24	0.95	0.60	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2008	0.13	1.05	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2009	0.17	0.95	0.60	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2010	0.17	1.05	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2011	0.17	1.05	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2012	0.17	1.05	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2013	0.17	1.05	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2014	0.17	1.05	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00

Resource Grouping - Gas - Central Alberta - Tight - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.44	0.75	0.55	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2003	0.31	0.45	0.30	7.00	0.22	20.00	0.20	45.00	0.12	90.00
2004	0.65	1.20	0.55	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2005	0.27	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.49	1.15	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	0.38	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	0.53	0.95	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2009	0.54	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.31	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.46	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.46	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.46	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.46	0.95	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - West Central Alberta - Conventional - Tertiary										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.26	0.65	0.30	7.00	0.25	20.00	0.20	45.00	0.10	90.00
2003	0.23	0.65	0.40	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2004	0.20	0.65	0.42	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2005	0.15	0.65	0.47	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.17	0.75	0.45	7.00	0.27	20.00	0.16	45.00	0.12	90.00
2007	0.16	0.70	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	0.19	0.65	0.50	7.00	0.40	20.00	0.16	45.00	0.12	90.00
2009	0.25	0.75	0.60	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2010	0.27	0.70	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.28	0.70	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.29	0.70	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.30	0.70	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.32	0.70	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - West Central Alberta - Conventional - Upper Cretaceous, Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.43	0.75	0.40	7.00	0.28	20.00	0.12	45.00	0.12	90.00
2003	0.47	0.75	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2004	0.37	0.65	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2005	0.30	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.28	0.95	0.42	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	0.38	0.50	0.33	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.41	0.80	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.36	0.50	0.30	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	0.47	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.41	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.41	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.41	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.41	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - West Central Alberta - Conventional - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.78	1.15	0.40	7.00	0.25	20.00	0.18	45.00	0.05	90.00
2003	0.59	0.95	0.40	7.00	0.30	20.00	0.16	45.00	0.05	90.00
2004	0.52	0.65	0.40	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2005	0.55	0.95	0.45	7.00	0.37	20.00	0.12	45.00	0.05	90.00
2006	0.17	1.65	0.45	7.00	0.16	20.00	0.14	45.00	0.05	90.00
2007	0.53	1.15	0.45	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2008	0.57	0.60	0.35	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2009	0.10	1.15	0.60	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2010	1.11	1.15	0.45	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2011	0.59	1.15	0.45	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2012	0.59	1.15	0.45	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2013	0.59	1.15	0.45	7.00	0.30	20.00	0.12	45.00	0.05	90.00
2014	0.59	1.15	0.45	7.00	0.30	20.00	0.12	45.00	0.05	90.00

Resource Grouping - Gas - West Central Alberta - Conventional - Lower Mannville, Jurassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.32	0.95	0.42	7.00	0.32	20.00	0.16	45.00	0.08	90.00
2003	0.77	0.85	0.34	7.00	0.23	20.00	0.14	45.00	0.08	90.00
2004	0.45	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.08	90.00
2005	0.68	0.65	0.42	7.00	0.35	20.00	0.14	45.00	0.08	90.00
2006	0.59	1.15	0.45	7.00	0.22	20.00	0.14	45.00	0.08	90.00
2007	0.55	0.95	0.43	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2008	0.61	0.75	0.40	7.00	0.30	20.00	0.14	45.00	0.08	90.00
2009	0.72	0.65	0.45	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2010	1.10	0.95	0.60	7.00	0.30	20.00	0.14	45.00	0.08	90.00
2011	1.11	0.95	0.60	7.00	0.30	20.00	0.14	45.00	0.08	90.00
2012	1.12	0.95	0.60	7.00	0.30	20.00	0.14	45.00	0.08	90.00
2013	1.12	0.95	0.60	7.00	0.30	20.00	0.14	45.00	0.08	90.00
2014	1.13	0.95	0.60	7.00	0.30	20.00	0.14	45.00	0.08	90.00

Resource Grouping - Gas - West Central Alberta - Conventional - Missisippian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.94	0.35	0.55	7.00	0.53	20.00	0.16	45.00	0.12	90.00
2003	0.61	0.55	0.35	7.00	0.38	20.00	0.16	45.00	0.12	90.00
2004	0.60	0.88	0.42	7.00	0.23	20.00	0.12	45.00	0.12	90.00
2005	0.79	0.20	0.27	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2006	0.93	0.95	0.46	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	0.63	0.65	0.30	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.37	1.45	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.76	0.95	0.70	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	1.11	0.85	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.27	0.85	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.44	0.85	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	1.60	0.85	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	1.77	0.85	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - West Central Alberta - Conventional - Upper Devonian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.21	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2003	1.24	0.45	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2004	1.38	0.10	0.12	7.00	0.20	20.00	0.14	45.00	0.12	90.00
2005	1.05	0.35	0.25	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2006	0.35	0.65	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	1.58	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2008	1.21	2.25	0.70	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	0.97	1.45	0.95	9.00	0.40	20.00	0.16	45.00	0.12	90.00
2010	0.74	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.64	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.57	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.53	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.50	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - West Central Alberta - Tight - Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.36	1.25	0.50	7.00	0.30	20.00	0.16	45.00	0.08	90.00
2003	0.47	0.95	0.40	7.00	0.23	20.00	0.14	45.00	0.08	90.00
2004	0.38	0.20	0.16	7.00	0.10	20.00	0.08	45.00	0.08	90.00
2005	0.45	0.95	0.50	7.00	0.12	20.00	0.08	45.00	0.08	90.00
2006	0.78	0.85	0.35	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2007	0.43	0.65	0.48	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2008	1.11	0.85	0.45	7.00	0.25	25.00	0.14	45.00	0.08	90.00
2009	0.46	1.25	0.30	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2010	0.52	0.85	0.45	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2011	0.52	0.85	0.45	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2012	0.52	0.85	0.45	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2013	0.52	0.85	0.45	7.00	0.25	20.00	0.14	45.00	0.08	90.00
2014	0.52	0.85	0.45	7.00	0.25	20.00	0.14	45.00	0.08	90.00

Resource Grouping - Gas - West Central Alberta - Tight - Mannville

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.88	0.65	0.42	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2003	0.53	0.65	0.40	7.00	0.25	20.00	0.14	45.00	0.12	90.00
2004	0.56	0.85	0.35	7.00	0.22	20.00	0.14	45.00	0.12	90.00
2005	0.50	0.65	0.35	7.00	0.23	20.00	0.16	45.00	0.12	90.00
2006	0.62	1.05	0.45	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	0.54	0.95	0.43	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.56	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.77	0.75	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	1.07	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	1.07	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	1.07	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	1.07	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	1.07	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Conventional - Upper Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	3.54	0.60	0.30	7.00	0.23	20.00	0.16	45.00	0.12	90.00
2003	1.29	0.65	0.40	7.00	0.22	20.00	0.14	45.00	0.12	90.00
2004	1.38	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2005	0.80	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	0.77	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	0.78	1.00	0.47	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	1.53	1.25	0.35	6.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	1.34	1.45	0.65	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2010	0.68	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.68	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.68	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.68	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.68	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Conventional - Colorado, Mannville

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	3.21	0.75	0.45	7.00	0.28	20.00	0.18	45.00	0.12	90.00
2003	1.77	0.60	0.30	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2004	1.59	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2005	0.74	0.70	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	1.14	0.65	0.37	7.00	0.33	20.00	0.20	45.00	0.12	90.00
2007	1.29	0.95	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2008	2.41	0.95	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2009	1.23	0.95	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	1.58	0.95	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.58	0.95	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.58	0.95	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	1.58	0.95	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	1.58	0.95	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Conventional - Jurassic, Triassic, Permian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.81	0.65	0.25	7.00	0.14	20.00	0.12	45.00	0.10	90.00
2003	6.48	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2004	3.85	0.40	0.25	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2005	3.14	0.65	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2006	5.04	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	7.08	0.85	0.45	7.00	0.27	20.00	0.16	45.00	0.12	90.00
2008	3.80	0.90	0.65	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2009	3.04	0.55	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	2.26	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	2.21	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	2.15	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	2.10	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	2.04	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Conventional - Mississippian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	4.64	0.40	0.30	7.00	0.12	20.00	0.10	45.00	0.10	90.00
2003	4.32	0.45	0.20	7.00	0.12	20.00	0.10	45.00	0.10	90.00
2004	3.20	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.10	90.00
2005	3.03	0.75	0.35	7.00	0.16	20.00	0.12	45.00	0.10	90.00
2006	2.13	0.10	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	3.68	0.65	0.40	7.00	0.30	20.00	0.20	45.00	0.10	90.00
2008	4.67	0.75	0.45	7.00	0.30	25.00	0.20	45.00	0.10	90.00
2009	3.96	0.60	0.45	10.00	0.30	25.00	0.16	45.00	0.10	90.00
2010	1.37	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2011	2.78	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2012	2.78	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2013	2.78	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2014	2.78	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.10	90.00

Resource Grouping - Gas - Central Foothills - Conventional - Upper Devonian, Middle Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	6.81	0.05	0.05	7.00	0.15	20.00	0.14	45.00	0.12	90.00
2003	2.97	0.10	0.30	7.00	0.12	20.00	0.10	45.00	0.10	90.00
2004	2.55	0.20	0.25	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2005	13.86	0.15	0.18	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	3.64	0.30	0.25	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2007	2.20	0.95	0.80	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	1.81	0.75	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	1.42	0.85	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	1.28	0.75	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.15	0.75	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.04	0.75	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.93	0.75	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.84	0.75	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Tight - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2004	1.18	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2005	2.24	0.65	0.50	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2006	0.22	0.20	0.12	7.00	0.05	20.00	0.05	45.00	0.05	90.00
2007	1.29	0.75	0.50	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2008	0.83	0.48	0.38	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	1.06	0.90	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2010	1.06	0.75	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.06	0.75	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.06	0.75	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	1.06	0.75	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	1.06	0.75	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Tight - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	2.09	1.20	0.80	7.00	0.60	500.00	0.16	500.00	0.12	500.00
2003	1.79	2.08	0.73	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2004	1.49	2.95	0.65	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2005	0.33	0.60	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	2.45	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2007	0.66	1.05	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.16	0.75	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	1.09	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	1.09	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	1.09	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	1.09	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	1.09	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	1.09	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Central Foothills - Tight - Jurassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2005	4.96	0.60	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	1.02	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	1.12	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	4.14	0.65	0.40	7.00	0.30	25.00	0.16	45.00	0.12	90.00
2009	2.78	0.75	0.55	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	2.68	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	2.68	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	2.68	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	2.68	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	2.68	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Kaybob - Conventional - Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.53	0.85	0.65	7.00	0.33	20.00	0.20	45.00	0.12	90.00
2003	0.55	1.10	0.55	7.00	0.33	20.00	0.20	45.00	0.12	90.00
2004	0.61	1.40	0.60	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2005	0.66	0.85	0.77	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.54	1.05	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	0.69	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.59	0.95	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2009	1.02	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	0.79	0.85	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.80	0.85	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.80	0.85	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.80	0.85	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.80	0.85	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Kaybob - Conventional - Mannville, Jurassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.77	0.99	0.59	7.00	0.32	20.00	0.18	45.00	0.12	90.00
2003	0.78	0.90	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2004	0.64	0.50	0.55	7.00	0.43	20.00	0.20	45.00	0.12	90.00
2005	0.83	1.05	0.63	7.00	0.27	20.00	0.16	45.00	0.12	90.00
2006	0.77	0.95	0.50	7.00	0.32	20.00	0.16	45.00	0.12	90.00
2007	0.76	0.65	0.45	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2008	1.10	1.35	0.47	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	1.27	0.65	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	1.16	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.17	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.17	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	1.17	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	1.17	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Kaybob - Conventional - Triassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.69	0.30	0.35	7.00	0.30	20.00	0.23	45.00	0.12	90.00
2003	1.28	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2004	1.49	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2005	1.27	0.70	0.45	7.00	0.28	20.00	0.20	45.00	0.12	90.00
2006	1.11	1.65	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	1.05	0.65	0.50	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2008	0.75	0.55	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2009	1.19	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	0.43	0.70	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	0.79	0.70	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	0.79	0.70	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	0.79	0.70	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	0.79	0.70	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Kaybob - Conventional - Upper Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.80	0.60	0.25	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2003	1.72	0.65	0.35	7.00	0.12	20.00	0.05	45.00	0.05	90.00
2004	0.04	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2005	0.07	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	1.28	0.95	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2007	0.88	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.76	1.25	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	1.07	0.85	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	1.16	0.95	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.00	0.95	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.00	0.95	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	1.00	0.95	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	1.00	0.95	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Kaybob - Tight - Colorado, Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.78	1.15	0.37	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2003	0.70	0.55	0.30	7.00	0.40	20.00	0.16	45.00	0.12	90.00
2004	0.68	0.85	0.40	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2005	0.69	0.90	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2006	0.77	0.85	0.50	7.00	0.28	20.00	0.16	45.00	0.12	90.00
2007	0.74	0.95	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.69	0.95	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	1.39	0.95	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	1.29	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	1.13	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	1.13	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	1.13	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	1.13	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Kaybob - Tight - Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.06	0.65	0.45	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2003	1.09	0.75	0.60	7.00	0.25	20.00	0.16	45.00	0.05	90.00
2004	1.02	0.95	0.60	7.00	0.27	20.00	0.14	45.00	0.05	90.00
2005	1.01	1.05	0.47	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2006	0.69	0.95	0.45	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2007	0.72	0.60	0.50	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2008	0.99	1.35	0.65	7.00	0.30	25.00	0.14	45.00	0.05	90.00
2009	1.28	1.05	0.60	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2010	1.98	1.05	0.55	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2011	2.18	1.05	0.55	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2012	2.40	1.05	0.55	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2013	2.64	1.05	0.55	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2014	2.90	1.05	0.55	7.00	0.30	20.00	0.14	45.00	0.05	90.00

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Upper Cretaceous										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.76	1.05	0.40	7.00	0.18	20.00	0.12	45.00	0.05	90.00
2003	0.71	1.15	0.48	7.00	0.23	20.00	0.14	45.00	0.05	90.00
2004	0.50	0.40	0.45	7.00	0.25	20.00	0.16	45.00	0.05	90.00
2005	0.48	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2006	0.32	0.55	0.25	7.00	0.14	20.00	0.10	45.00	0.05	90.00
2007	0.49	1.45	0.40	7.00	0.18	20.00	0.12	45.00	0.05	90.00
2008	0.56	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2009	0.59	0.85	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2010	0.45	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2011	0.54	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2012	0.54	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2013	0.54	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2014	0.54	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.05	90.00

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Upper Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.99	1.10	0.40	7.00	0.18	20.00	0.14	45.00	0.08	90.00
2003	0.57	1.20	0.30	7.00	0.18	20.00	0.12	45.00	0.08	90.00
2004	0.50	0.65	0.40	7.00	0.22	20.00	0.10	45.00	0.08	90.00
2005	0.51	1.15	0.40	7.00	0.28	20.00	0.12	45.00	0.08	90.00
2006	0.68	1.15	0.40	7.00	0.18	20.00	0.14	45.00	0.08	90.00
2007	0.87	1.15	0.50	7.00	0.30	20.00	0.18	45.00	0.08	90.00
2008	0.57	1.35	0.55	7.00	0.25	20.00	0.16	45.00	0.08	90.00
2009	0.24	0.65	0.40	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2010	0.53	0.75	0.45	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2011	0.53	0.75	0.45	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2012	0.53	0.75	0.45	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2013	0.53	0.75	0.45	7.00	0.20	20.00	0.14	45.00	0.08	90.00
2014	0.53	0.75	0.45	7.00	0.20	20.00	0.14	45.00	0.08	90.00

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Mannville, Jurassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.32	0.20	0.18	7.00	0.14	20.00	0.10	45.00	0.05	90.00
2003	0.68	0.95	0.60	7.00	0.25	20.00	0.12	45.00	0.05	90.00
2004	1.12	1.65	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2005	0.46	0.65	0.55	7.00	0.35	20.00	0.20	45.00	0.05	90.00
2006	0.54	0.85	0.50	7.00	0.32	20.00	0.18	45.00	0.05	90.00
2007	0.38	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2008	0.89	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2009	0.69	0.75	0.45	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2010	1.44	0.85	0.50	7.00	0.30	20.00	0.16	45.00	0.05	90.00
2011	1.44	0.85	0.50	7.00	0.30	20.00	0.16	45.00	0.05	90.00
2012	1.44	0.85	0.50	7.00	0.30	20.00	0.16	45.00	0.05	90.00
2013	1.44	0.85	0.50	7.00	0.30	20.00	0.16	45.00	0.05	90.00
2014	1.44	0.85	0.50	7.00	0.30	20.00	0.16	45.00	0.05	90.00

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Triassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	2.31	0.60	0.30	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2003	2.12	0.95	0.40	7.00	0.25	20.00	0.15	45.00	0.05	90.00
2004	1.59	0.65	0.50	7.00	0.30	20.00	0.14	45.00	0.05	90.00
2005	1.21	0.65	0.42	7.00	0.33	20.00	0.14	45.00	0.05	90.00
2006	1.36	0.65	0.37	7.00	0.20	20.00	0.14	45.00	0.05	90.00
2007	0.73	0.65	0.50	7.00	0.35	20.00	0.18	45.00	0.05	90.00
2008	0.90	0.80	0.45	7.00	0.30	20.00	0.16	45.00	0.05	90.00
2009	1.78	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2010	2.33	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2011	2.57	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2012	2.83	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2013	3.11	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2014	3.42	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00

Resource Grouping - Gas - Alberta Deep Basin - Conventional - Upper Devonian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	4.58	0.85	0.50	7.00	0.25	20.00	0.12	45.00	0.12	90.00
2003	2.90	0.85	0.70	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2004	4.14	0.45	0.22	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2005	4.57	1.65	0.85	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2006	0.26	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	8.92	0.30	0.20	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2008	1.58	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	4.61	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	3.09	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2011	3.09	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2012	3.09	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2013	3.09	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2014	3.09	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Alberta Deep Basin - Tight - Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.09	1.05	0.25	7.00	0.16	20.00	0.16	45.00	0.12	90.00
2003	0.67	0.65	0.40	7.00	0.25	20.00	0.14	45.00	0.12	90.00
2004	0.87	0.85	0.40	7.00	0.20	20.00	0.14	45.00	0.12	90.00
2005	0.64	0.90	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2006	0.60	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	0.60	1.05	0.45	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2008	0.68	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	0.81	0.75	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	1.04	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2011	1.27	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2012	1.58	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2013	1.95	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2014	2.41	0.95	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Alberta Deep Basin - Tight - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.70	0.65	0.40	7.00	0.50	20.00	0.14	45.00	0.10	90.00
2003	1.16	0.65	0.40	7.00	0.30	20.00	0.14	45.00	0.10	90.00
2004	0.98	0.65	0.40	7.00	0.35	20.00	0.16	45.00	0.10	90.00
2005	0.59	0.60	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00
2006	0.48	0.50	0.33	7.00	0.20	20.00	0.16	45.00	0.10	90.00
2007	0.89	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00
2008	1.30	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.10	90.00
2009	1.07	1.15	0.45	7.00	0.20	20.00	0.16	45.00	0.10	90.00
2010	0.96	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00
2011	0.89	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00
2012	0.76	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00
2013	0.66	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00
2014	0.56	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.10	90.00

Resource Grouping - Gas - Alberta Deep Basin - Tight - Mannville, Jurassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.27	0.85	0.40	7.00	0.32	20.00	0.18	45.00	0.10	90.00
2003	1.09	0.65	0.50	7.00	0.32	20.00	0.14	45.00	0.10	90.00
2004	0.74	0.60	0.45	7.00	0.27	20.00	0.14	45.00	0.10	90.00
2005	0.60	0.60	0.45	7.00	0.28	20.00	0.14	45.00	0.10	90.00
2006	0.63	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2007	0.76	0.65	0.40	7.00	0.33	20.00	0.16	45.00	0.10	90.00
2008	1.10	0.90	0.45	7.00	0.30	20.00	0.16	45.00	0.10	90.00
2009	1.04	0.65	0.50	7.00	0.30	20.00	0.16	45.00	0.10	90.00
2010	1.14	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2011	1.14	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2012	1.14	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2013	1.14	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.10	90.00
2014	1.14	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.10	90.00

Resource Grouping - Gas - Alberta Deep Basin - Tight - Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.04	0.50	0.30	7.00	0.10	20.00	0.10	45.00	0.05	90.00
2003	1.64	0.60	0.30	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2004	3.35	1.25	0.40	7.00	0.25	20.00	0.16	45.00	0.05	90.00
2005	1.05	1.25	0.40	7.00	0.20	20.00	0.16	45.00	0.05	90.00
2006	0.72	1.05	0.37	7.00	0.22	20.00	0.14	45.00	0.05	90.00
2007	0.45	1.05	0.65	7.00	0.35	20.00	0.14	45.00	0.05	90.00
2008	1.52	1.65	0.60	7.00	0.35	20.00	0.16	45.00	0.05	90.00
2009	1.47	1.25	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2010	2.44	1.25	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2011	2.69	1.25	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2012	2.96	1.25	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2013	3.25	1.25	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00
2014	3.58	1.25	0.55	7.00	0.25	20.00	0.14	45.00	0.05	90.00

Resource Grouping - Gas - Northeast Alberta - Conventional - Mannville, Upper Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.31	0.23	0.27	7.00	0.23	20.00	0.20	45.00	0.16	90.00
2003	0.29	0.40	0.30	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2004	0.24	0.18	0.32	7.00	0.27	20.00	0.20	45.00	0.16	90.00
2005	0.25	0.65	0.45	7.00	0.27	20.00	0.16	45.00	0.16	90.00
2006	0.20	0.65	0.40	7.00	0.27	20.00	0.23	45.00	0.16	90.00
2007	0.23	0.65	0.40	7.00	0.32	20.00	0.20	45.00	0.16	90.00
2008	0.22	0.65	0.45	7.00	0.40	20.00	0.20	45.00	0.16	90.00
2009	0.19	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2010	0.20	0.65	0.35	7.00	0.25	20.00	0.20	45.00	0.16	90.00
2011	0.20	0.65	0.35	7.00	0.25	20.00	0.20	45.00	0.16	90.00
2012	0.20	0.65	0.35	7.00	0.25	20.00	0.20	45.00	0.16	90.00
2013	0.20	0.65	0.35	7.00	0.25	20.00	0.20	45.00	0.16	90.00
2014	0.20	0.65	0.35	7.00	0.25	20.00	0.20	45.00	0.16	90.00

Resource Grouping - Gas - Peace River - Conventional - Upper Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.56	0.20	0.25	7.00	0.33	20.00	0.50	45.00	0.20	90.00
2003	0.94	0.25	0.50	7.00	0.48	20.00	0.32	45.00	0.20	90.00
2004	0.44	0.65	0.40	7.00	0.30	20.00	0.33	45.00	0.20	90.00
2005	0.41	0.65	0.50	7.00	0.33	20.00	0.25	45.00	0.20	90.00
2006	0.29	0.95	0.50	7.00	0.40	20.00	0.30	45.00	0.20	90.00
2007	0.32	0.65	0.30	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2008	0.26	0.75	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	0.25	0.75	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	0.24	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.23	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.22	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.22	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.21	0.75	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Peace River - Conventional - Colorado, Upper Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.45	0.85	0.50	7.00	0.90	20.00	0.30	45.00	0.18	90.00
2003	0.47	0.30	0.40	7.00	0.50	20.00	0.30	45.00	0.18	90.00
2004	0.76	0.65	0.65	7.00	0.55	20.00	0.30	45.00	0.18	90.00
2005	0.65	0.65	0.47	7.00	0.42	20.00	0.30	45.00	0.18	90.00
2006	0.47	0.65	0.40	7.00	0.75	20.00	0.30	45.00	0.18	90.00
2007	0.61	0.35	0.55	7.00	0.80	20.00	0.30	45.00	0.18	90.00
2008	0.41	0.65	0.65	7.00	0.70	20.00	0.30	45.00	0.18	90.00
2009	0.46	0.65	0.60	7.00	0.70	20.00	0.30	45.00	0.18	90.00
2010	0.61	0.70	0.60	7.00	0.70	20.00	0.30	45.00	0.18	90.00
2011	0.61	0.70	0.60	7.00	0.70	20.00	0.30	45.00	0.18	90.00
2012	0.61	0.70	0.60	7.00	0.70	20.00	0.30	45.00	0.18	90.00
2013	0.61	0.70	0.60	7.00	0.70	20.00	0.30	45.00	0.18	90.00
2014	0.61	0.70	0.60	7.00	0.70	20.00	0.30	45.00	0.18	90.00

Resource Grouping - Gas - Peace River - Conventional - Middle Mannville, Lower Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.12	1.25	0.57	7.00	0.40	20.00	0.32	45.00	0.12	90.00
2003	0.82	0.65	0.75	7.00	0.45	20.00	0.25	45.00	0.12	90.00
2004	0.63	0.30	0.50	7.00	0.53	20.00	0.30	45.00	0.12	90.00
2005	0.73	0.95	0.95	7.00	0.38	20.00	0.30	45.00	0.12	90.00
2006	0.63	0.95	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2007	0.76	1.25	0.70	7.00	0.50	20.00	0.25	45.00	0.12	90.00
2008	0.51	1.25	0.30	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2009	0.67	1.25	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2010	0.51	1.25	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2011	0.56	1.25	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2012	0.56	1.25	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2013	0.56	1.25	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2014	0.56	1.25	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Peace River - Conventional - Upper Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	2.15	1.65	0.85	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2003	1.35	0.65	0.65	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2004	0.63	0.40	0.30	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2005	0.48	1.25	0.50	7.00	0.30	20.00	0.22	45.00	0.16	90.00
2006	0.88	0.65	0.50	7.00	0.45	20.00	0.25	45.00	0.16	90.00
2007	0.76	1.45	0.80	7.00	0.40	20.00	0.20	45.00	0.16	90.00
2008	0.68	0.55	0.75	7.00	0.40	20.00	0.25	45.00	0.16	90.00
2009	0.94	1.35	0.55	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2010	0.65	1.35	0.50	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2011	0.76	1.35	0.50	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2012	0.76	1.35	0.50	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2013	0.76	1.35	0.50	7.00	0.30	20.00	0.20	45.00	0.16	90.00
2014	0.76	1.35	0.50	7.00	0.30	20.00	0.20	45.00	0.16	90.00

Resource Grouping - Gas - Peace River - Conventional - Lower Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.25	1.25	0.75	7.00	0.25	20.00	0.20	45.00	0.12	90.00
2003	0.54	1.25	0.40	7.00	0.20	20.00	0.12	45.00	0.12	90.00
2004	1.08	0.95	0.60	7.00	0.32	20.00	0.16	45.00	0.12	90.00
2005	0.62	1.25	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2006	0.71	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	1.09	1.75	0.60	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2008	1.07	0.45	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2009	1.97	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	2.07	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	2.17	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	2.28	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	2.40	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	2.52	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Peace River - Conventional - Mississippian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	3.41	1.25	1.00	7.00	0.55	20.00	0.25	45.00	0.12	90.00
2003	1.34	0.55	0.50	7.00	0.40	20.00	0.16	45.00	0.12	90.00
2004	0.76	0.25	0.35	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2005	0.77	0.20	0.65	7.00	0.28	20.00	0.20	45.00	0.12	90.00
2006	0.71	1.05	0.55	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2007	0.64	1.25	0.75	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2008	1.12	0.60	0.70	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2009	1.27	0.75	0.85	7.00	0.45	20.00	0.25	45.00	0.12	90.00
2010	0.56	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2011	0.98	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2012	0.98	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2013	0.98	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2014	0.98	0.85	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Peace River - Conventional - Upper Devonian, Middle Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	5.35	0.25	0.20	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2003	2.97	0.65	1.55	7.00	0.55	20.00	0.25	45.00	0.12	90.00
2004	1.61	0.65	0.55	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2005	3.29	0.20	0.70	7.00	0.80	20.00	0.20	45.00	0.12	90.00
2006	0.68	1.25	0.75	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	2.21	2.95	1.25	7.00	0.65	20.00	0.20	45.00	0.12	90.00
2008	0.66	1.25	0.85	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2009	0.41	1.25	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2010	1.06	1.25	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2011	1.06	1.25	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2012	1.06	1.25	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2013	1.06	1.25	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2014	1.06	1.25	0.65	7.00	0.35	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Peace River - Tight - Triassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.43	1.50	0.70	7.00	0.50	20.00	0.25	45.00	0.12	90.00
2003	0.37	1.05	0.40	7.00	0.28	20.00	0.20	45.00	0.12	90.00
2004	1.81	1.30	0.53	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2005	0.96	1.50	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.48	1.25	0.80	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2007	0.76	1.85	0.60	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	0.84	0.60	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	0.68	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	1.81	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2011	1.81	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2012	1.81	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2013	1.81	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2014	1.81	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Peace River - Tight - Lower Triassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.08	0.65	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2003	0.81	0.98	0.52	7.00	0.25	20.00	0.14	45.00	0.12	90.00
2004	0.77	1.15	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2005	0.65	0.95	0.75	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2006	0.74	1.35	0.50	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2007	0.58	0.65	0.50	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2008	1.05	0.70	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	1.40	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	1.58	0.70	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	1.66	0.70	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	1.74	0.70	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	1.83	0.70	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	1.92	0.70	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northwest Alberta - Conventional - Mannville

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.19	0.65	0.50	7.00	0.16	20.00	0.18	45.00	0.12	90.00
2003	0.13	0.70	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2004	0.11	0.30	0.25	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2005	0.09	0.20	0.30	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.13	0.30	0.20	7.00	0.23	20.00	0.16	45.00	0.12	90.00
2007	0.19	0.65	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	0.25	0.30	0.25	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2009	0.32	0.40	0.25	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	0.31	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	0.31	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	0.31	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	0.31	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	0.31	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northwest Alberta - Conventional - Mississippian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.52	0.55	0.30	7.00	0.27	20.00	0.22	45.00	0.12	90.00
2003	0.25	0.65	0.25	7.00	0.16	20.00	0.16	45.00	0.12	90.00
2004	0.43	0.65	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2005	0.22	0.55	0.30	7.00	0.27	20.00	0.18	45.00	0.12	90.00
2006	0.13	0.65	0.20	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2007	0.28	0.75	0.55	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2008	0.28	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2009	0.14	0.35	0.25	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	0.22	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	0.22	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	0.22	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	0.22	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	0.22	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northwest Alberta - Conventional - Upper Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.65	1.25	0.90	7.00	0.30	20.00	0.25	45.00	0.12	90.00
2003	1.59	0.65	0.55	7.00	0.58	20.00	0.25	45.00	0.12	90.00
2004	0.93	1.05	0.40	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2005	0.69	1.25	0.80	7.00	0.55	20.00	0.25	45.00	0.12	90.00
2006	0.87	1.95	0.60	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	0.29	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	0.73	1.85	0.70	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2009	2.41	1.75	0.75	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2010	0.64	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.80	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.80	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.80	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.80	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - Northwest Alberta - Conventional - Middle Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.14	1.45	1.25	7.00	0.65	20.00	0.40	45.00	0.18	90.00
2003	1.07	0.85	0.95	7.00	0.70	20.00	0.40	45.00	0.18	90.00
2004	0.86	0.95	0.80	7.00	0.60	20.00	0.45	45.00	0.18	90.00
2005	0.96	1.00	0.95	7.00	0.70	20.00	0.45	45.00	0.18	90.00
2006	0.75	2.25	1.25	7.00	0.50	20.00	0.25	45.00	0.18	90.00
2007	0.71	1.65	1.35	7.00	0.90	20.00	0.30	45.00	0.18	90.00
2008	1.01	1.45	1.05	7.00	0.60	20.00	0.40	45.00	0.18	90.00
2009	1.17	1.45	1.05	7.00	0.65	20.00	0.20	45.00	0.18	90.00
2010	0.57	1.45	1.05	7.00	0.65	20.00	0.35	45.00	0.18	90.00
2011	0.71	1.45	1.05	7.00	0.65	20.00	0.35	45.00	0.18	90.00
2012	0.71	1.45	1.05	7.00	0.65	20.00	0.35	45.00	0.18	90.00
2013	0.71	1.45	1.05	7.00	0.65	20.00	0.35	45.00	0.18	90.00
2014	0.71	1.45	1.05	7.00	0.65	20.00	0.35	45.00	0.18	90.00

Resource Grouping - Gas - BC Deep Basin - Conventional - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2003	5.50	1.95	1.45	10.00	0.60	25.00	0.25	45.00	0.12	90.00
2004	5.65	0.45	0.85	7.00	0.35	15.00	0.45	45.00	0.12	90.00
2005	4.25	0.80	0.65	7.00	0.20	18.00	0.25	35.00	0.12	500.00
2006	0.28	1.45	0.65	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2007	0.15	0.70	0.45	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	0.43	0.50	0.35	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2009	0.55	0.50	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	0.13	0.50	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	0.13	0.50	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	0.13	0.50	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	0.13	0.50	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	0.13	0.50	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - BC Deep Basin - Conventional - Lower Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2005	2.45	0.15	0.25	20.00	0.18	30.00	0.60	45.00	0.25	80.00
2006	0.85	0.45	0.32	8.00	0.75	30.00	0.22	45.00	0.12	500.00
2007	1.95	0.15	0.35	7.00	0.22	20.00	0.16	45.00	0.12	500.00
2008	2.04	0.10	0.65	10.00	0.30	25.00	0.16	60.00	0.12	90.00
2009	2.27	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	2.49	0.50	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	2.76	0.50	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	3.06	0.50	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	3.38	0.50	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	3.75	0.50	0.40	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - BC Deep Basin - Tight - Colorado										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.54	0.95	0.45	7.00	0.45	20.00	0.05	45.00	0.05	90.00
2003	0.73	0.65	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2004	0.51	1.35	0.40	7.00	0.20	20.00	0.12	45.00	0.05	90.00
2005	0.09	0.65	0.40	7.00	0.16	20.00	0.08	45.00	0.05	90.00
2006	1.56	1.35	0.95	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2007	1.49	1.95	1.05	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2008	0.96	2.25	1.25	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2009	1.84	2.25	1.25	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2010	1.43	1.65	0.65	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2011	1.43	1.65	0.65	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2012	1.43	1.65	0.65	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2013	1.43	1.65	0.65	7.00	0.35	20.00	0.12	45.00	0.05	90.00
2014	1.43	1.65	0.65	7.00	0.35	20.00	0.12	45.00	0.05	90.00

Resource Grouping - Gas - BC Deep Basin - Tight - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.06	1.85	0.90	7.00	0.45	20.00	0.20	45.00	0.12	90.00
2003	1.77	0.85	0.40	7.00	0.30	20.00	0.28	45.00	0.12	90.00
2004	2.32	0.99	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2005	1.77	1.25	0.40	7.00	0.25	20.00	0.30	45.00	0.12	90.00
2006	1.73	1.05	0.40	7.00	0.33	20.00	0.16	45.00	0.12	90.00
2007	1.13	1.45	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	2.78	1.10	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	1.61	0.65	0.50	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	2.35	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	2.35	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	2.35	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	2.35	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	2.35	0.85	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - BC Deep Basin - Tight - Lower Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2006	1.40	1.85	0.63	7.00	0.25	20.00	0.14	45.00	0.12	90.00
2007	1.53	1.45	0.65	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	2.24	1.25	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	1.86	0.65	0.50	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	4.00	1.05	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	4.00	1.05	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	4.00	1.05	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	4.00	1.05	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	4.00	1.05	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Fort St John - Conventional - Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.63	0.95	0.35	7.00	0.20	20.00	0.23	45.00	0.18	90.00
2003	0.59	0.85	0.40	7.00	0.23	20.00	0.24	45.00	0.18	90.00
2004	0.43	0.60	0.40	7.00	0.24	20.00	0.23	45.00	0.18	90.00
2005	0.29	0.55	0.40	7.00	0.24	20.00	0.22	45.00	0.18	90.00
2006	0.29	0.85	0.35	7.00	0.25	20.00	0.22	45.00	0.18	90.00
2007	0.30	0.65	0.48	7.00	0.27	20.00	0.22	45.00	0.18	90.00
2008	0.37	0.95	0.45	7.00	0.27	20.00	0.22	45.00	0.18	90.00
2009	0.23	0.95	0.45	7.00	0.30	20.00	0.25	45.00	0.18	90.00
2010	0.21	0.85	0.45	7.00	0.30	20.00	0.25	45.00	0.18	90.00
2011	0.19	0.85	0.45	7.00	0.30	20.00	0.25	45.00	0.18	90.00
2012	0.17	0.85	0.45	7.00	0.30	20.00	0.25	45.00	0.18	90.00
2013	0.15	0.85	0.45	7.00	0.30	20.00	0.25	45.00	0.18	90.00
2014	0.14	0.85	0.45	7.00	0.30	20.00	0.25	45.00	0.18	90.00

Resource Grouping - Gas - Fort St John - Conventional - Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.90	0.85	0.45	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2003	0.73	1.15	0.40	7.00	0.28	20.00	0.18	45.00	0.12	90.00
2004	0.70	0.85	0.48	7.00	0.35	20.00	0.16	45.00	0.12	90.00
2005	0.60	0.95	0.50	7.00	0.31	20.00	0.18	45.00	0.12	90.00
2006	0.51	0.95	0.50	7.00	0.22	20.00	0.18	45.00	0.12	90.00
2007	0.60	1.05	0.40	7.00	0.28	20.00	0.18	45.00	0.12	90.00
2008	0.69	1.25	0.40	7.00	0.28	20.00	0.18	45.00	0.12	90.00
2009	0.61	1.35	0.55	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2010	0.52	1.05	0.50	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2011	0.50	1.05	0.50	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2012	0.47	1.05	0.50	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2013	0.45	1.05	0.50	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2014	0.43	1.05	0.50	7.00	0.30	20.00	0.18	45.00	0.12	90.00

Resource Grouping - Gas - Fort St John - Conventional - Permian, Mississippian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.65	0.18	0.85	7.00	0.18	20.00	0.16	45.00	0.12	500.00
2003	0.26	0.05	0.12	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2004	1.50	0.10	0.32	12.00	0.40	50.00	0.20	70.00	0.12	500.00
2005	1.50	1.00	0.25	10.00	0.15	20.00	0.12	45.00	0.12	500.00
2006	0.51	0.10	0.45	7.00	0.60	20.00	0.20	45.00	0.12	90.00
2007	3.20	0.15	0.20	7.00	0.15	20.00	0.12	45.00	0.15	500.00
2008	2.10	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	1.66	2.05	0.95	7.00	0.40	20.00	0.18	45.00	0.12	90.00
2010	2.37	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	2.37	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	2.37	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	2.37	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	2.37	1.05	0.45	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Fort St John - Conventional - Upper Devonian, Middle Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	11.06	0.65	1.30	7.00	0.65	20.00	0.30	45.00	0.20	90.00
2003	6.66	0.40	0.30	7.00	0.26	20.00	0.16	45.00	0.12	90.00
2004	1.14	0.75	0.35	7.00	0.20	20.00	0.12	45.00	0.10	90.00
2005	1.46	0.65	0.65	7.00	0.32	20.00	0.25	45.00	0.12	90.00
2006	0.82	0.75	0.45	7.00	0.30	20.00	0.18	45.00	0.12	90.00
2007	1.37	0.55	0.27	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2010	1.23	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	1.23	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	1.23	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	1.23	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	1.23	0.75	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Fort St John - Tight - Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2006	0.70	0.65	0.57	7.00	0.27	20.00	0.16	45.00	0.12	90.00
2007	1.09	0.65	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	1.21	0.65	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	1.50	0.30	0.25	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	4.00	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	4.00	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	4.00	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	4.00	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	4.00	0.65	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northeast BC - Conventional - Lower Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.12	0.45	0.20	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2003	0.57	1.35	0.40	7.00	0.22	20.00	0.12	40.00	0.05	500.00
2004	0.18	0.55	0.10	5.00	0.05	20.00	0.05	500.00	0.05	90.00
2005	1.00	0.35	0.25	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	0.23	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008	0.41	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2009	0.17	0.95	0.35	4.00	0.22	20.00	0.16	45.00	0.12	500.00
2010	0.29	0.65	0.35	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2011	0.29	0.65	0.35	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2012	0.29	0.65	0.35	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2013	0.29	0.65	0.35	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2014	0.29	0.65	0.35	7.00	0.22	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northeast BC - Conventional - Permian, Mississippian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	2.07	0.30	0.25	7.00	0.40	20.00	0.32	45.00	0.16	90.00
2003	1.18	0.40	0.45	7.00	0.38	20.00	0.18	45.00	0.12	90.00
2004	2.08	0.40	0.50	7.00	0.48	20.00	0.18	45.00	0.12	90.00
2005	0.99	0.45	0.30	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2006	0.42	0.95	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	0.24	0.20	0.12	7.00	0.10	20.00	0.08	45.00	0.05	90.00
2008	0.40	0.95	0.40	7.00	0.18	20.00	0.16	45.00	0.12	90.00
2009	0.77	0.20	0.18	7.00	0.16	20.00	0.14	45.00	0.12	90.00
2010	0.20	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	0.34	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	0.34	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	0.34	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	0.34	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northeast BC - Conventional - Upper Devonian, Middle Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	4.79	0.95	0.85	7.00	0.60	20.00	0.25	45.00	0.12	90.00
2003	2.86	0.95	0.40	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2004	0.71	0.95	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2005	2.11	0.30	0.20	7.00	0.12	20.00	0.25	45.00	0.12	90.00
2006	0.93	0.65	0.20	7.00	0.08	20.00	0.05	45.00	0.05	90.00
2007	0.04	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	0.50	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2009	0.06	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	0.38	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.38	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.38	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.38	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.38	0.75	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northeast BC - Tight - Upper Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.23	0.95	0.55	7.00	0.20	20.00	0.14	45.00	0.12	90.00
2003	1.18	1.05	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2004	1.11	1.15	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2005	0.98	1.15	0.45	7.00	0.23	20.00	0.16	45.00	0.12	90.00
2006	0.62	1.15	0.45	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2007	0.66	1.45	0.55	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2008	0.99	1.45	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	0.59	1.15	0.40	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2010	0.96	1.05	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2011	0.96	1.05	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2012	0.96	1.05	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2013	0.96	1.05	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2014	0.96	1.05	0.45	7.00	0.25	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Northeast BC - Shale - Middle Devonian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2006	1.40	1.65	0.75	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	1.52	1.75	0.62	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2008	1.37	1.55	0.65	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2009	4.00	0.85	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	6.00	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2011	8.00	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2012	8.00	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2013	8.00	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2014	8.00	1.25	0.60	7.00	0.30	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - BC Foothills - Conventional - Colorado, Mannville										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2004	0.96	0.20	0.12	7.00	0.20	20.00	0.30	45.00	0.12	90.00
2005	2.29	0.55	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2006	2.59	0.65	0.60	7.00	0.40	20.00	0.20	45.00	0.12	90.00
2007	1.11	0.35	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	1.64	1.45	0.60	7.00	0.27	20.00	0.20	45.00	0.12	90.00
2009	1.47	0.75	0.55	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2010	2.46	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	2.40	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	3.78	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	3.97	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	4.16	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - BC Foothills - Conventional - Triassic, Permian, Mississippian										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	3.79	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2003	12.70	0.45	0.25	7.00	0.20	20.00	0.14	45.00	0.12	90.00
2004	8.61	0.40	0.23	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2005	5.95	0.30	0.22	7.00	0.10	20.00	0.08	45.00	0.05	90.00
2006	9.30	0.30	0.14	7.00	0.12	20.00	0.10	45.00	0.10	90.00
2007	3.42	0.30	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2008	3.45	0.60	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2009	4.91	0.40	0.30	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2010	1.18	0.50	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2011	3.18	0.50	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2012	3.18	0.50	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2013	3.18	0.50	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2014	3.18	0.50	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - BC Foothills - Tight - Triassic										
Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.05	0.20	0.10	7.00	0.08	20.00	0.05	45.00	0.05	90.00
2003	3.34	0.95	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2004	2.29	0.20	0.42	7.00	0.65	20.00	0.25	45.00	0.12	90.00
2005	0.95	1.45	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2006	0.58	0.37	0.30	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2007	0.52	0.75	0.40	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	1.48	0.75	0.40	7.00	0.25	20.00	0.20	45.00	0.12	90.00
2009	1.13	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	2.61	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	2.74	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	2.88	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	3.02	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	3.18	0.85	0.45	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - BC Foothills - Tight - Lower Triassic

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	1.41	0.25	0.20	7.00	0.10	20.00	0.08	45.00	0.05	90.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	3.09	0.45	0.25	7.00	0.12	20.00	0.08	45.00	0.05	90.00
2005	1.70	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	8.48	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.14	0.65	0.40	7.00	0.22	20.00	0.16	45.00	0.12	90.00
2010	2.07	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2011	1.10	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2012	1.10	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2013	1.10	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00
2014	1.10	0.65	0.40	7.00	0.20	20.00	0.16	45.00	0.12	90.00

Resource Grouping - Gas - Southwest Saskatchewan - Tight - Upper Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.06	0.55	0.30	7.00	0.22	20.00	0.20	45.00	0.12	90.00
2003	0.08	0.55	0.30	7.00	0.22	20.00	0.22	45.00	0.12	90.00
2004	0.07	0.75	0.27	7.00	0.23	20.00	0.20	45.00	0.12	90.00
2005	0.09	0.75	0.42	7.00	0.28	20.00	0.24	45.00	0.12	90.00
2006	0.09	0.95	0.42	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2007	0.07	0.95	0.40	7.00	0.24	20.00	0.18	45.00	0.12	90.00
2008	0.07	0.90	0.50	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2009	0.08	0.85	0.55	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2010	0.05	0.85	0.50	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2011	0.05	0.85	0.50	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2012	0.05	0.85	0.50	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2013	0.05	0.85	0.50	7.00	0.25	20.00	0.18	45.00	0.12	90.00
2014	0.05	0.85	0.50	7.00	0.25	20.00	0.18	45.00	0.12	90.00

Resource Grouping - Gas - West Saskatchewan - Conventional - Colorado

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.11	0.75	0.40	7.00	0.30	20.00	0.35	45.00	0.12	90.00
2003	0.11	0.95	0.60	7.00	0.25	20.00	0.16	45.00	0.12	90.00
2004	0.12	1.35	0.50	7.00	0.23	20.00	0.14	45.00	0.12	90.00
2005	0.10	1.15	0.47	7.00	0.30	20.00	0.14	45.00	0.12	90.00
2006	0.11	1.15	0.50	7.00	0.30	20.00	0.16	45.00	0.12	90.00
2007	0.10	0.95	0.50	7.00	0.35	20.00	0.20	45.00	0.12	90.00
2008	0.08	1.25	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	0.10	1.35	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	0.11	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.12	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.13	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.13	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.14	1.25	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Resource Grouping - Gas - West SK - Conventional - Middle Mannville, Lower Mannville, Mississippian

Connection Year	Initial Production per Connection MMcf/d	1st Decline Rate	2nd Decline Rate	Months to 2nd Decline Rate	3rd Decline Rate	Months to 3rd Decline Rate	4th Decline Rate	Months to 4th Decline Rate	5th Decline Rate	Months to 5th Decline Rate
2002	0.29	0.45	0.45	7.00	0.45	20.00	0.28	45.00	0.12	90.00
2003	0.27	0.95	0.60	7.00	0.44	20.00	0.30	45.00	0.12	90.00
2004	0.28	0.65	0.70	7.00	0.55	20.00	0.30	45.00	0.12	90.00
2005	0.24	0.70	0.80	7.00	0.50	20.00	0.40	45.00	0.12	90.00
2006	0.19	0.80	0.52	7.00	0.42	20.00	0.30	45.00	0.12	90.00
2007	0.21	0.67	0.52	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2008	0.16	0.65	0.60	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2009	0.27	0.70	0.55	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2010	0.13	0.70	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2011	0.18	0.70	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2012	0.18	0.70	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2013	0.18	0.70	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00
2014	0.18	0.70	0.50	7.00	0.30	20.00	0.20	45.00	0.12	90.00

Appendix B

B1 Factors for Allocation of Gas-Intent Drill Days by Area

Historical Gas-Intent Drill Days by Area

Year	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskatchewan	18 - West Saskat-chewan	19 - East Saskat-chewan
2002	1,129	9,136	1,899	549	4,480	3,333	5,332	5,793	1,350	11,171	11	5,709	931	620	1,174	1,216	0	9,124	812	2,872	0
2003	2,443	17,005	2,917	448	5,289	5,009	6,660	5,991	2,231	14,227	37	4,191	1,097	2,563	2,315	4,147	0	8,514	1,108	3,627	0
2004	5,394	15,743	2,008	565	4,859	5,987	7,634	6,773	2,152	19,193	38	5,711	834	6,008	4,668	7,276	0	1,398	4,070	319	1
2005	10,834	13,983	3,134	448	6,660	9,650	9,289	5,226	2,462	22,080	48	5,010	658	6,021	2,589	4,031	0	9,965	1,892	2,644	30
2006	10,410	12,288	2,011	669	8,445	6,825	10,031	6,053	2,854	23,506	49	5,018	697	10,191	4,672	5,551	0	2,145	3,218	109	0
2007	12,547	9,835	1,269	648	4,314	3,330	6,440	3,721	2,500	14,918	1,055	1,892	449	3,046	3,550	1,988	0	2,805	6,130	619	15
2008	5,552	7,791	1,506	80	2,422	3,965	8,004	4,341	2,981	15,410	747	2,902	523	4,427	5,770	1,805	432	2,816	6,832	1,806	8
2009	4,821	2,665	316	19	449	885	3,154	1,904	2,296	8,615	202	1,478	175	2,542	3,765	796	402	1,479	797	106	0
2010	3,182	2,619	406	24	576	1,135	3,995	2,299	5,658	12,321	159	2,646	225	3,677	6,375	854	2,100	1,117	2,416	440	0

Historical Fraction of Total Gas-Intent Drill Days by Area

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskatchewan	18 - West Saskat-chewan	19 - East Saskat-chewan
2002	0.0169	0.1371	0.0285	0.0082	0.0672	0.0500	0.0800	0.0869	0.0203	0.1676	0.0002	0.0857	0.0140	0.0093	0.0176	0.0182	0.0000	0.1369	0.0122	0.0431	0.0000
2003	0.0272	0.1893	0.0325	0.0050	0.0589	0.0558	0.0741	0.0667	0.0248	0.1584	0.0004	0.0467	0.0122	0.0285	0.0258	0.0462	0.0000	0.0948	0.0123	0.0404	0.0000
2004	0.0536	0.1564	0.0200	0.0056	0.0483	0.0595	0.0759	0.0673	0.0214	0.1907	0.0004	0.0567	0.0083	0.0597	0.0464	0.0723	0.0000	0.0139	0.0404	0.0032	0.0000
2005	0.0929	0.1199	0.0269	0.0038	0.0571	0.0827	0.0796	0.0448	0.0211	0.1893	0.0004	0.0429	0.0056	0.0516	0.0222	0.0346	0.0000	0.0854	0.0162	0.0227	0.0003
2006	0.0907	0.1071	0.0175	0.0058	0.0736	0.0595	0.0874	0.0528	0.0249	0.2049	0.0004	0.0437	0.0061	0.0888	0.0407	0.0484	0.0000	0.0187	0.0280	0.0009	0.0000
2007	0.1548	0.1213	0.0156	0.0080	0.0532	0.0411	0.0794	0.0459	0.0308	0.1840	0.0130	0.0233	0.0055	0.0376	0.0438	0.0245	0.0000	0.0346	0.0756	0.0076	0.0002
2008	0.0693	0.0972	0.0188	0.0010	0.0302	0.0495	0.0999	0.0542	0.0372	0.1923	0.0093	0.0362	0.0065	0.0553	0.0720	0.0225	0.0054	0.0352	0.0853	0.0225	0.0001
2009	0.1308	0.0723	0.0086	0.0005	0.0122	0.0240	0.0855	0.0516	0.0623	0.2337	0.0055	0.0401	0.0048	0.0690	0.1021	0.0216	0.0109	0.0401	0.0216	0.0029	0.0000
2010	0.0609	0.0501	0.0078	0.0005	0.0110	0.0217	0.0765	0.0440	0.1083	0.2359	0.0030	0.0507	0.0043	0.0704	0.1221	0.0164	0.0402	0.0214	0.0463	0.0084	0.0000

Projected Gas-Intent Drill Days by Area - Mid-Range Price Case

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskatchewan	18 - West Saskat-chewan	19 - East Saskat-chewan
2011	3,625	2,419	354	40	576	1,182	4,489	1,003	3,619	11,092	150	728	125	2,939	6,745	1,154	2,100	1,337	2,411	410	0
2012	2,016	1,530	343	35	301	758	4,890	638	2,709	8,569	122	1,076	122	2,532	8,490	840	1,200	1,051	1,085	234	0
2013	376	384	352	37	136	426	5,162	262	2,774	8,649	107	969	149	1,585	8,019	533	1,082	1,191	453	67	0
2014	159	123	500	23	72	263	4,682	108	2,499	8,205	65	979	92	1,484	7,827	422	1,190	1,465	291	36	0

Projected Fraction of Total Gas-Intent Drill Days by Area - Mid-Range Price Case

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskatchewan	18 - West Saskat-chewan	19 - East Saskat-chewan
2011	0.0780	0.0520	0.0076	0.0009	0.0124	0.0254	0.0965	0.0216	0.0778	0.2386	0.0032	0.0156	0.0027	0.0632	0.1451	0.0248	0.0452	0.0288	0.0519	0.0088	0.0000
2012	0.0523	0.0397	0.0089	0.0009	0.0078	0.0197	0.1269	0.0166	0.0703	0.2223	0.0032	0.0279	0.0032	0.0657	0.2203	0.0218	0.0311	0.0273	0.0282	0.0061	0.0000
2013	0.0115	0.0118	0.0108	0.0011	0.0042	0.0130	0.1578	0.0080	0.0848	0.2644	0.0033	0.0296	0.0046	0.0484	0.2451	0.0163	0.0331	0.0364	0.0139	0.0020	0.0000
2014	0.0052	0.0040	0.0164	0.0008	0.0023	0.0086	0.1536	0.0035	0.0820	0.2692	0.0021	0.0321	0.0030	0.0487	0.2568	0.0138	0.0390	0.0481	0.0095	0.0012	0.0000

Projected Gas-Intent Drill Days by Area - Higher Price Case

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskat-chewan	18 - West Saskat-chewan	19 - East Saskatchewan
2011	2,016	1,530	343	35	301	758	4,890	638	2,709	8,569	122	1,076	122	2,532	8,490	840	2,250	1,051	1,085	234	0
2012	1,730	384	652	37	136	476	5,612	262	3,124	9,149	107	719	124	1,360	8,694	483	2,326	1,241	403	67	0
2013	1,465	123	500	23	72	263	4,682	108	2,699	8,305	65	819	82	1,359	8,177	372	2,490	1,515	241	36	0
2014	1,540	854	889	15	32	242	4,579	32	3,527	7,938	43	1,094	224	1,533	7,964	184	2,689	1,709	217	122	0

Projected Fraction of Total Gas-Intent Drill Days by Area - Higher Price Case

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskat-chewan	18 - West Saskat-chewan	19 - East Saskatchewan
2011	0.0509	0.0386	0.0087	0.0009	0.0076	0.0191	0.1235	0.0161	0.0684	0.2164	0.0031	0.0272	0.0031	0.0639	0.2144	0.0212	0.0568	0.0265	0.0274	0.0059	0.0000
2012	0.0466	0.0104	0.0176	0.0010	0.0037	0.0128	0.1513	0.0071	0.0842	0.2467	0.0029	0.0194	0.0033	0.0367	0.2344	0.0130	0.0627	0.0335	0.0109	0.0018	0.0000
2013	0.0439	0.0037	0.0150	0.0007	0.0021	0.0079	0.1402	0.0032	0.0808	0.2487	0.0019	0.0245	0.0024	0.0407	0.2449	0.0111	0.0746	0.0454	0.0072	0.0011	0.0000
2014	0.0435	0.0241	0.0251	0.0004	0.0009	0.0068	0.1292	0.0009	0.0996	0.2241	0.0012	0.0309	0.0063	0.0433	0.2248	0.0052	0.0759	0.0482	0.0061	0.0034	0.0000

Projected Gas-Intent Drill Days by Area - Lower Price Case

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskat-chewan	18 - West Saskat-chewan	19 - East Saskatchewan
2011	2,016	1,530	343	35	301	758	4,890	638	2,709	8,569	122	1,076	122	2,532	8,490	840	1,200	1,051	1,085	234	0
2012	0	80	31	0	0	133	2,729	0	2,046	5,527	0	208	0	921	6,002	280	496	668	0	0	0
2013	0	27	17	0	0	125	1,038	0	561	5,323	0	193	1	1,002	6,323	259	600	564	0	0	0
2014	0	9	7	0	0	118	480	0	225	4,683	0	179	0	1,001	6,261	158	564	423	0	0	0

Projected Fraction of Total Gas-Intent Drill Days by Area - Lower Price Case

DrlYr	00 - Alberta CBM	01 - Southern Alberta	02 - Southwest Alberta	03 - Southern Foothills	04 - Eastern Alberta	05 - Central Alberta	06 - West Central Alberta	07 - Central Foothills	08 - Kaybob	09 - Alberta Deep Basin	10 - Northeast Alberta	11 - Peace River	12 - Northwest Alberta	13 - BC Deep Basin	14 - Fort St. John	15 - Northeast BC (excl Shale)	15 - Northeast BC (Shale)	16 - BC Foothills	17 - Southwest Saskat-chewan	18 - West Saskat-chewan	19 - East Saskatchewan
2011	0.0523	0.0397	0.0089	0.0009	0.0078	0.0197	0.1269	0.0166	0.0703	0.2223	0.0032	0.0279	0.0032	0.0657	0.2203	0.0218	0.0311	0.0273	0.0282	0.0061	0.0000
2012	0.0000	0.0042	0.0016	0.0000	0.0000	0.0070	0.1427	0.0000	0.1070	0.2891	0.0000	0.0109	0.0000	0.0482	0.3139	0.0147	0.0259	0.0349	0.0000	0.0000	0.0000
2013	0.0000	0.0017	0.0011	0.0000	0.0000	0.0078	0.0648	0.0000	0.0350	0.3321	0.0000	0.0120	0.0000	0.0625	0.3944	0.0161	0.0374	0.0352	0.0000	0.0000	0.0000
2014	0.0000	0.0006	0.0005	0.0000	0.0000	0.0083	0.0340	0.0000	0.0159	0.3319	0.0000	0.0127	0.0000	0.0710	0.4438	0.0112	0.0400	0.0300	0.0000	0.0000	0.0000

B2 Detailed Gas-Intent Drilling and Gas Connection Projections by Case

Mid-Range Price Case							
Area name	Projected Annual Numberof Wells Targeted to Resource Grouping			Connection Ratio	Projected Annual Number of Connections for Resource Grouping		
	2012	2013	2014		2012	2013	2014
Gas Connections							
00 - Alberta CBM	91	36	23	1.383	126	49	31
01 - Southern Alberta	183	45	20	1.174	214	50	22
Tight Portion	156	25	9	1.200	188	30	11
02 - Southwest Alberta	82	117	103	1.162	96	139	122
Tight Portion	3	1	1	1.031	3	1	1
03 - Southern Foothills	1	0	0	1.038	1	0	0
04 - Eastern Alberta	47	24	11	1.077	50	26	12
Tight Portion	13	7	4	0.963	13	7	3
05 - Central Alberta	80	47	32	1.071	86	49	33
Tight Portion	28	21	19	1.018	28	22	20
06 - West Central Alberta	514	459	388	1.013	521	465	395
Tight Portion	113	108	91	0.860	97	93	78
07 - Central Foothills	5	2	1	1.139	6	2	1
Tight Portion	1	0	0	0.859	1	0	0
08 - Kaybob	129	116	105	0.994	128	116	105
Tight Portion	26	24	22	1.000	26	24	22
Other Tight Portion	67	63	60	1.022	68	65	61
09 - Alberta Deep Basin	332	305	275	1.027	341	310	275
Tight Portion	19	18	17	0.802	16	14	13
Other Tight Portion	291	275	256	0.990	288	271	252
10 - Northeast Alberta	36	22	15	0.840	30	18	12
11 - Peace River	92	86	43	0.844	78	71	37
Tight Portion	15	19	22	0.910	13	18	20
12 - Northwest Alberta	26	16	5	0.743	19	12	4
13 - BC Deep Basin	43	40	26	1.033	45	42	28
Montney Portion	6	6	4	1.000	6	6	4
Other Tight Portion	13	10	4	0.942	12	10	4
14 - Fort St. John	277	263	238	1.049	290	270	241
Montney Portion	178	174	159	1.000	178	174	159
15 - Northeast BC	69	67	56	1.000	69	67	56
Horn River Shale Portion	39	43	43	1.000	39	43	43
Tight Portion	24	20	11	1.000	24	20	11
16 - BC Foothills	22	27	23	0.933	21	25	22
Tight Portion	7	9	9	0.672	4	6	9
17 - Southwest Saskatchewan	121	77	16	1.024	124	79	17
Tight Portion	121	77	16	1.024	124	79	17
18 - West Saskatchewan	9	5	3	1.108	10	6	4
19 - East Saskatchewan	0	0	0	N/A	0	0	0
Subtotal: Gas - Conventional (non-tight)	955	825	624	1.052	1,005	871	666
Subtotal: Gas - Tight	1,074	850	694	1	1,084	834	676
Montney portion of Tight	229	222	202	1	226	219	198
Subtotal: Gas - CBM	91	36	23	1.383	126	49	31
Subtotal: Gas - Shale	39	43	43	1.000	39	43	43
Gas Connections - CBM Breakdown							
AB - Main HSC	91	36	23	1.383	126	49	31
AB - Mannville CBM	0	0	0		0	0	0
AB - Other CBM	0	0	0		0	0	0
Subtotal: Gas - CBM	91	36	23	1.383	126	49	31
Total: All Gas	**2,159**	**1,755**	**1,384**	**1.044**	**2,255**	**1,798**	**1,416**

Higher Price Case							
Area name	**Projected Annual Number of Wells Targeted to Resource Grouping**			**Connection Ratio**	**Projected Annual Number of Connections for Resource Grouping**		
	2012	**2013**	**2014**		**2012**	**2013**	**2014**
Gas Connections							
00 - Alberta CBM	91	36	91	1.383	126	49	126
01 - Southern Alberta	183	45	214	1.174	214	50	219
Tight Portion	156	25	9	1.200	188	30	11
02 - Southwest Alberta	152	117	193	1.184	180	139	230
Tight Portion	3	1	9	1.031	3	1	9
03 - Southern Foothills	1	0	0	1.038	1	0	0
04 - Eastern Alberta	47	24	11	1.077	50	26	12
Tight Portion	13	7	4	0.963	13	7	3
05 - Central Alberta	87	47	38	1.066	93	49	40
Tight Portion	34	21	26	1.017	35	22	26
06 - West Central Alberta	553	459	464	1.015	562	465	474
Tight Portion	122	108	91	0.861	105	93	78
07 - Central Foothills	5	2	1	1.139	6	2	1
Tight Portion	1	0	0	0.859	1	0	0
08 - Kaybob	145	125	176	0.994	144	125	175
Montney Portion	37	33	53	1.000	37	33	53
Other Tight Portion	78	72	91	1.019	79	74	92
09 - Alberta Deep Basin	348	308	284	1.019	354	312	282
Montney Portion	29	21	26	0.802	24	17	21
Other Tight Portion	307	279	265	0.983	301	274	259
10 - Northeast Alberta	36	22	15	0.840	30	18	12
11 - Peace River	75	74	101	0.852	64	61	82
Tight Portion	15	19	22	0.910	13	18	20
12 - Northwest Alberta	20	14	33	0.787	16	10	23
13 - BC Deep Basin	36	36	43	1.053	38	38	44
Montney Portion	5	6	10	1.000	5	6	10
Other Tight Portion	6	7	16	0.948	6	7	15
14 - Fort St. John	297	273	260	1.046	311	281	263
Montney Portion	200	188	184	1.000	200	188	184
15 - Northeast BC	82	80	84	1.000	82	80	84
Horn River Shale Portion	54	58	73	1.000	54	58	73
Tight Portion	24	20	11	1.000	24	20	11
16 - BC Foothills	23	29	32	0.940	22	27	30
Tight Portion	9	12	14	0.504	4	9	12
17 - Southwest Saskatchewan	107	64	58	1.024	110	66	59
Tight Portion	107	64	58	1.024	110	66	59
18 - West Saskatchewan	9	5	18	1.108	10	6	20
19 - East Saskatchewan	0	0	0	N/A	0	0	0
Subtotal: Gas - Conventional (non-tight)	1,015	795	1,081	1.074	1,090	846	1,127
Subtotal: Gas - Tight	1,138	872	873	1	1,143	854	852
Montney portion of Tight	271	248	273	1	265	243	267
Subtotal: Gas - CBM	91	36	91	1.383	126	49	126
Subtotal: Gas - Shale	54	58	73	1.000	54	58	73
Gas Connections - CBM Breakdown							
AB - Main HSC	91	36	91	1.383	126	49	126
AB - Mannville CBM	0	0	0		0	0	0
AB - Other CBM	0	0	0		0	0	0
Subtotal: Gas - CBM	91	36	91	1.383	126	49	126
Total: All Gas	**2,297**	**1,761**	**2,118**	**1.050**	**2,413**	**1,807**	**2,178**

Lower Price Case							
Area name	Projected Annual Number of Wells Targeted to Resource Grouping			Connection Ratio	Projected Annual Number of Connections for Resource Grouping		
	2011	2012	2013		2011	2012	2013
Gas Connections							
00 - Alberta CBM	0	0	0		0	0	0
01 - Southern Alberta	19	7	2	1.020	20	7	2
Tight Portion	0	0	0		0	0	0
02 - Southwest Alberta	7	4	2	1.206	9	5	2
Tight Portion	0	0	0	1.056	0	0	0
03 - Southern Foothills	0	0	0		0	0	0
04 - Eastern Alberta	0	0	0	0.677	0	0	0
Tight Portion	0	0	0		0	0	0
05 - Central Alberta	18	17	16	1.013	18	17	16
Tight Portion	18	17	16	1.013	18	17	16
06 - West Central Alberta	275	107	58	1.010	278	110	60
Tight Portion	65	11	1	0.860	56	10	1
07 - Central Foothills	0	0	0	1.312	0	0	0
Tight Portion	0	0	0		0	0	0
08 - Kaybob	94	26	11	1.004	94	26	11
Montney Portion	25	6	3	1.000	25	6	3
Other Tight Portion	64	18	8	1.022	65	19	8
09 - Alberta Deep Basin	197	189	173	0.987	195	186	170
Montney Portion	14	13	12	0.802	11	10	10
Other Tight Portion	191	184	172	0.986	189	181	170
10 - Northeast Alberta	0	0	0	0.840	0	0	0
11 - Peace River	16	13	10	0.822	13	11	9
Tight Portion	6	7	8	0.911	5	6	7
12 - Northwest Alberta	0	0	0	0.277	0	0	0
13 - BC Deep Basin	23	26	26	1.061	25	27	27
Montney Portion	0	0	0		0	0	0
Other Tight Portion	3	7	7	0.936	3	6	7
14 - Fort St. John	190	200	198	0.986	187	197	195
Montney Portion	144	151	147	1.000	144	151	147
15 - Northeast BC	36	38	31	1.000	36	38	31
Horn River Shale Portion	18	22	21	1.000	18	22	21
Tight Portion	18	17	10	1.000	18	17	10
16 - BC Foothills	12	10	8	0.897	11	9	7
Tight Portion	2	2	3	2.686	4	2	2
17 - Southwest Saskatchewan	0	0	0		0	0	0
Tight Portion	0	0	0		0	0	0
18 - West Saskatchewan	0	0	0		0	0	0
19 - East Saskatchewan	0	0	0	N/A	0	0	0
Subtotal: Gas - Conventional (non-tight)	321	186	128	1.033	332	190	130
Subtotal: Gas - Tight	548	430	385	1	534	423	379
Montney portion of Tight	183	170	163	1	180	167	161
Subtotal: Gas - CBM	0	0	0		0	0	0
Subtotal: Gas - Shale	18	22	21	1.000	18	22	21
Gas Connections - CBM Breakdown							
AB - Main HSC	0	0	0		0	0	0
AB - Mannville CBM	0	0	0		0	0	0
AB - Other CBM	0	0	0		0	0	0
Subtotal: Gas - CBM	0	0	0		0	0	0
Total: All Gas	**887**	**637**	**533**	**0.997**	**884**	**634**	**530**

APPENDIX C

Deliverability Details by Case

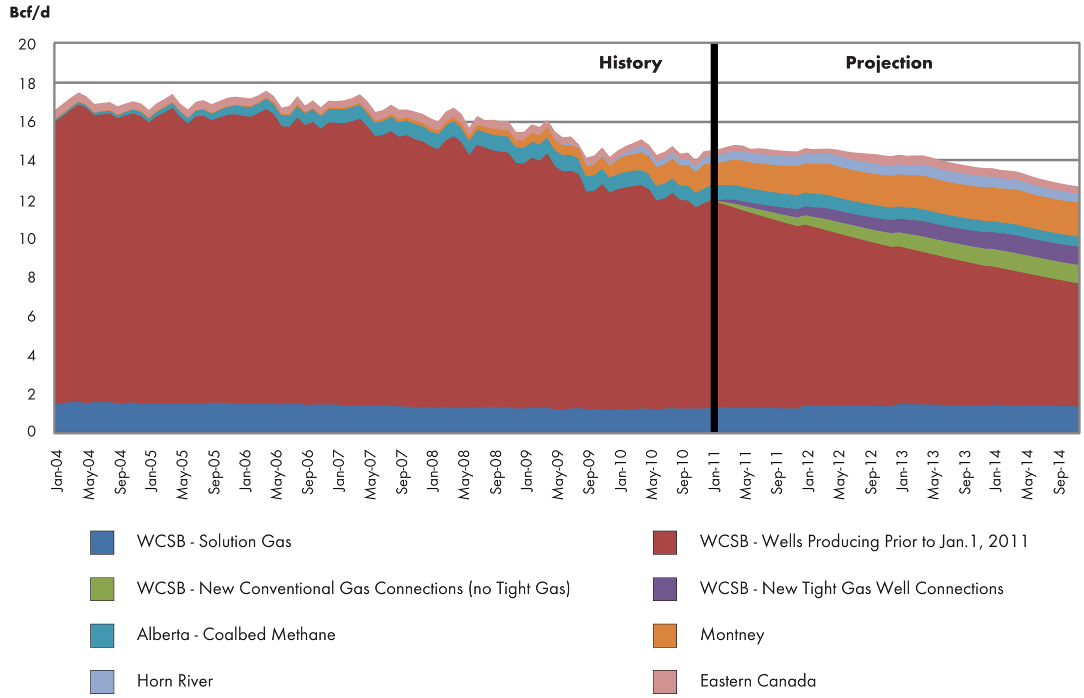
C.1 - Canadian Gas Deliverability by Area/Resource – Mid-Range Price Case

Area/Resource	Historical				Projection					
	2010		2011*		2012		2013		2014	
	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d
00 - Alberta CBM	23.0	812	22.0	777	20.4	721	18.6	655	16.9	597
HSC Portion	17.9	633	16.9	598	15.6	550	14.1	498	12.8	451
Mannville Portion	3.0	107	2.9	104	2.9	101	2.6	92	2.4	85
Other CBM Portion	2.0	72	2.1	75	2.0	70	1.8	65	1.7	61
01 - Southern Alberta	38.4	1,355	36.1	1,274	31.7	1,121	27.2	959	23.1	815
Tight Portion	25.1	885	23.9	843	20.8	735	17.7	626	15.1	532
02 - Southwest Alberta	8.0	283	7.4	262	7.2	254	7.4	262	7.7	271
Tight Portion	2.3	82	2.2	76	1.9	66	1.6	56	1.3	47
03 - Southern Foothills	4.6	163	4.7	166	4.1	145	3.6	126	3.1	109
04 - Eastern Alberta	18.8	662	17.1	603	16.5	582	16.0	563	15.1	534
Tight Portion	0.4	15	0.4	14	0.3	12	0.3	11	0.3	9
05 - Central Alberta	22.3	787	20.4	721	19.1	675	17.8	629	16.1	568
Tight Portion	1.9	68	1.8	63	1.8	62	1.7	59	1.5	55
06 - West Central Alberta	44.6	1,574	43.9	1,549	45.1	1,593	44.6	1,574	42.9	1,516
Tight Portion	15.0	528	14.7	519	14.0	496	13.2	465	12.2	429
07 - Central Foothills	23.0	814	21.2	747	18.6	655	16.1	569	13.9	492
Tight Portion	1.3	45	1.2	41	1.1	37	0.9	32	0.8	27
08 - Kaybob	23.0	813	21.7	767	21.5	758	20.5	725	19.2	679
Montney Portion	2.9	104	3.1	108	3.5	124	3.9	136	4.1	144
Other Tight Portion	7.4	261	6.7	238	6.3	221	5.8	205	5.3	188
09 - Alberta Deep Basin	59.0	2,082	57.0	2,014	58.2	2,053	58.0	2,047	57.0	2,012
Montney Portion	2.5	88	3.0	105	4.0	140	5.2	183	6.4	226
Other Tight Portion	46.6	1,646	45.0	1,587	45.0	1,589	44.1	1,558	42.7	1,507
10 - Northeast Alberta	12.0	423	10.4	366	9.4	333	8.6	304	7.9	279
11 - Peace River	20.0	705	19.7	695	18.9	667	17.9	633	16.5	582
Tight Portion	6.2	219	6.3	221	5.6	196	5.1	180	4.8	168
12 - Northwest Alberta	10.6	374	9.2	326	8.3	293	7.2	254	6.0	211
Tight Portion	0.0	1	0.0	1	0.0	1	0.0	1	0.0	1
13 - BC Deep Basin	16.0	564	19.1	675	19.1	675	18.3	645	17.3	609
Montney Portion	1.9	69	2.2	79	2.5	90	2.2	79	2.0	72
Other Tight Portion	11.1	392	13.0	460	11.9	419	10.6	373	9.2	326
14 - Fort St. John	34.0	1,199	45.8	1,618	52.4	1,851	55.4	1,955	56.6	1,998
Montney Portion	18.1	640	27.7	976	35.8	1,263	40.2	1,418	42.7	1,508
15 - Northeast BC	15.9	563	19.8	698	21.1	746	21.5	761	19.2	677
Horn River Shale Portion	8.7	306	14.0	495	15.7	555	16.6	587	14.8	522
Tight Portion	5.7	200	4.3	153	4.1	145	3.8	133	3.4	118
16 - BC Foothills	16.0	566	17.2	607	15.5	546	14.0	492	12.6	444
Tight Portion	3.4	119	4.9	174	4.3	152	3.8	133	3.3	117
17 - Southwest Saskatchewan	8.1	285	6.8	239	6.0	211	5.2	184	4.5	159
Tight Portion	7.5	264	6.3	221	5.5	194	4.7	166	4.0	142
18 - West Saskatchewan	4.1	146	3.8	134	3.5	123	3.1	111	2.8	101
19 - East Saskatchewan	2.0	71	2.1	74	2.4	85	2.5	88	2.5	90
22 - Yukon and Northwest Territories	0.6	20	0.5	17	0.4	15	0.4	13	0.3	11
Total Conventional (no tight, no solution gas)	**176.4**	**6,228**	**165.6**	**5,844**	**153.7**	**5,427**	**141.5**	**4,995**	**129.1**	**4,558**
Total Tight	**159.3**	**5,624**	**166.5**	**5,877**	**168.3**	**5,942**	**164.6**	**5,812**	**159.1**	**5,617**
Montney Portion	**25.5**	**901**	**35.9**	**1269**	**45.8**	**1617**	**51.4**	**1816**	**55.2**	**1950**
Total Solution Gas	**36.6**	**1292**	**37.9**	**1337**	**41.3**	**1459**	**42.5**	**1499**	**41.4**	**1460**
Total CBM	**23.0**	**812**	**22.0**	**777**	**20.4**	**721**	**18.6**	**655**	**16.9**	**597**
Total Shale	**8.7**	**306**	**14.0**	**495**	**15.7**	**555**	**16.6**	**587**	**14.8**	**522**
Total WCSB	**404.0**	**14,262**	**405.9**	**14,330**	**399.6**	**14,105**	**383.8**	**13,548**	**361.3**	**12,754**
Atlantic Canada	8.9	313	7.6	269	9.9	350	12.6	444	11.1	392
Other Canada	0.5	16	0.5	16	0.4	15	0.4	14	0.4	14
Total Canada	**413.3**	**14,592**	**414.0**	**14,615**	**409.9**	**14,469**	**396.8**	**14,006**	**372.8**	**13,160**

*matched to 2011 actual production for January – August.

FIGURE C1

Outlook for Total Canadian Gas Deliverability - Mid-Range Price Case



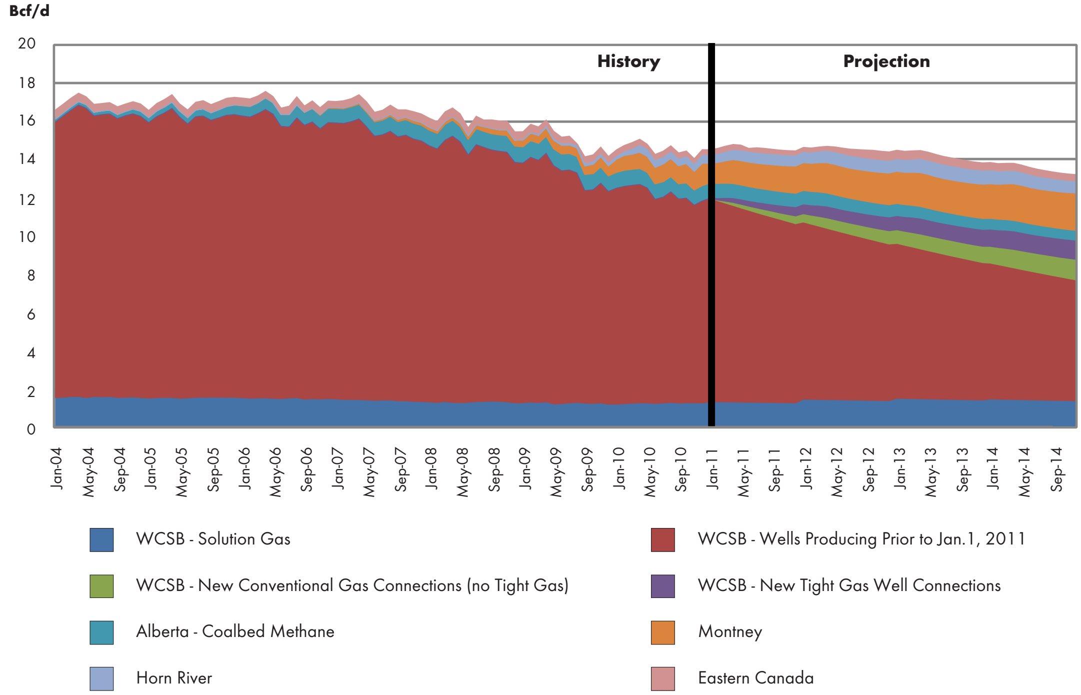
C.2 - Canadian Gas Deliverability by Area/Resource - Higher Price Case

Area/Resource	Historical				Projection					
	2010		2011*		2012		2013		2014	
	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d
00 - Alberta CBM	23.0	812	22.0	777	20.4	721	18.6	655	17.0	598
HSC Portion	17.9	633	16.9	598	15.6	550	14.1	498	12.8	452
Mannville Portion	3.0	107	2.9	104	2.9	101	2.6	92	2.4	85
Other CBM Portion	2.0	72	2.1	75	2.0	70	1.8	65	1.7	61
01 - Southern Alberta	38.4	1,355	36.1	1274	31.7	1,121	27.2	959	23.4	827
Tight Portion	25.1	885	23.9	843	20.8	735	17.7	626	15.1	532
02 - Southwest Alberta	8.0	283	7.4	262	7.8	274	8.2	290	9.0	317
Tight Portion	2.3	82	2.2	76	1.9	66	1.6	56	1.4	48
03 - Southern Foothills	4.6	163	4.7	166	4.1	145	3.6	126	3.1	109
04 - Eastern Alberta	18.8	662	17.1	603	16.5	582	16.0	563	15.1	534
Tight Portion	0.4	15	0.4	14	0.3	12	0.3	11	0.3	9
05 - Central Alberta	22.3	787	20.4	721	19.2	676	17.8	630	16.2	570
Tight Portion	1.9	68	1.8	63	1.8	63	1.7	60	1.6	57
06 - West Central Alberta	44.6	1,574	43.9	1549	45.4	1,603	45.0	1,588	43.5	1,535
Tight Portion	15.0	528	14.7	519	14.1	498	13.3	468	12.2	431
07 - Central Foothills	23.0	814	21.2	747	18.6	655	16.1	569	13.9	492
Tight Portion	1.3	45	1.2	41	1.1	37	0.9	32	0.8	27
08 - Kaybob	23.0	813	21.7	767	21.8	769	21.1	746	20.9	737
Montney Portion	2.9	104	3.1	108	3.7	132	4.4	155	5.4	191
Other Tight Portion	7.4	261	6.7	238	6.3	221	5.8	205	5.3	188
09 - Alberta Deep Basin	59.0	2,082	57.0	2014	58.6	2,070	59.0	2,081	58.5	2,066
Montney Portion	2.5	88	3.0	105	4.4	154	6.0	213	7.8	277
Other Tight Portion	46.6	1,646	45.0	1587	45.1	1,592	44.2	1,561	42.8	1,510
10 - Northeast Alberta	12.0	423	10.4	366	9.4	333	8.6	304	7.9	279
11 - Peace River	20.0	705	19.7	695	18.6	658	17.4	614	16.7	589
Tight Portion	6.2	219	6.3	221	5.6	196	5.1	180	4.8	168
12 - Northwest Alberta	10.6	374	9.2	326	8.3	292	7.2	253	6.1	216
Tight Portion	0.0	1	0.0	1	0.0	1	0.0	1	0.0	1
13 - BC Deep Basin	16.0	564	19.1	675	18.9	667	17.8	629	17.4	613
Montney Portion	1.9	69	2.2	79	2.5	88	2.1	75	2.2	77
Other Tight Portion	11.1	392	13.0	460	11.7	413	10.2	359	9.2	324
14 - Fort St. John	34.0	1,199	45.8	1618	53.4	1,886	57.4	2,026	59.5	2,102
Montney Portion	18.1	640	27.7	976	36.8	1,298	42.2	1,488	45.7	1,612
15 - Northeast BC	15.9	563	19.8	698	22.3	788	23.9	844	21.8	771
Horn River Shale Portion	8.7	306	14.0	495	16.9	597	19.0	671	17.5	617
Tight Portion	5.7	200	4.3	153	4.1	145	3.8	133	3.4	118
16 - BC Foothills	16.0	566	17.2	607	15.5	546	13.9	492	12.7	449
Tight Portion	3.4	119	4.9	174	4.3	152	3.8	135	3.4	121
17 - Southwest Saskatchewan	8.1	285	6.8	239	6.0	211	5.2	183	4.5	159
Tight Portion	7.5	264	6.3	221	5.5	194	4.7	166	4.0	142
18 - West Saskatchewan	4.1	146	3.8	134	3.5	123	3.1	111	2.9	101
19 - East Saskatchewan	2.0	71	2.1	74	2.4	85	2.5	88	2.5	90
22 - Yukon and Northwest Territories	0.6	20	0.5	17	0.4	15	0.4	13	0.3	11
Total Conventional (no tight, no solution gas)	**176.4**	**6,228**	**165.6**	**5844**	**154.2**	**5,445**	**142.1**	**5,015**	**131.9**	**4,657**
Total Tight	**159.3**	**5,624**	**166.5**	**5877**	**169.9**	**5,997**	**167.8**	**5,925**	**165.2**	**5,833**
Montney Portion	**25.5**	**901**	**35.9**	**1269**	**47.4**	**1672**	**54.7**	**1932**	**61.1**	**2156**
Total Solution Gas	**36.6**	**1292**	**37.9**	**1337**	**41.3**	**1459**	**42.5**	**1499**	**41.4**	**1460**
Total CBM	**23.0**	**812**	**22.0**	**777**	**20.4**	**721**	**18.6**	**655**	**17.0**	**598**
Total Shale	**8.7**	**306**	**14.0**	**495**	**16.9**	**597**	**19.0**	**671**	**17.5**	**617**
Total WCSB	**404.0**	**14,262**	**405.9**	**14330**	**402.8**	**14,220**	**389.9**	**13,765**	**373.0**	**13,167**
Atlantic Canada	8.9	313	7.6	269	9.9	350	12.6	444	11.1	392
Other Canada	0.5	16	0.5	16	0.4	15	0.4	14	0.4	14
Total Canada	**413.3**	**14,592**	**414.0**	**14615**	**413.1**	**14,585**	**402.9**	**14,224**	**384.5**	**13,572**

*matched to 2011 actual production for January – August.

FIGURE C2

Outlook for Canadian Gas Deliverability – Higher Price Case



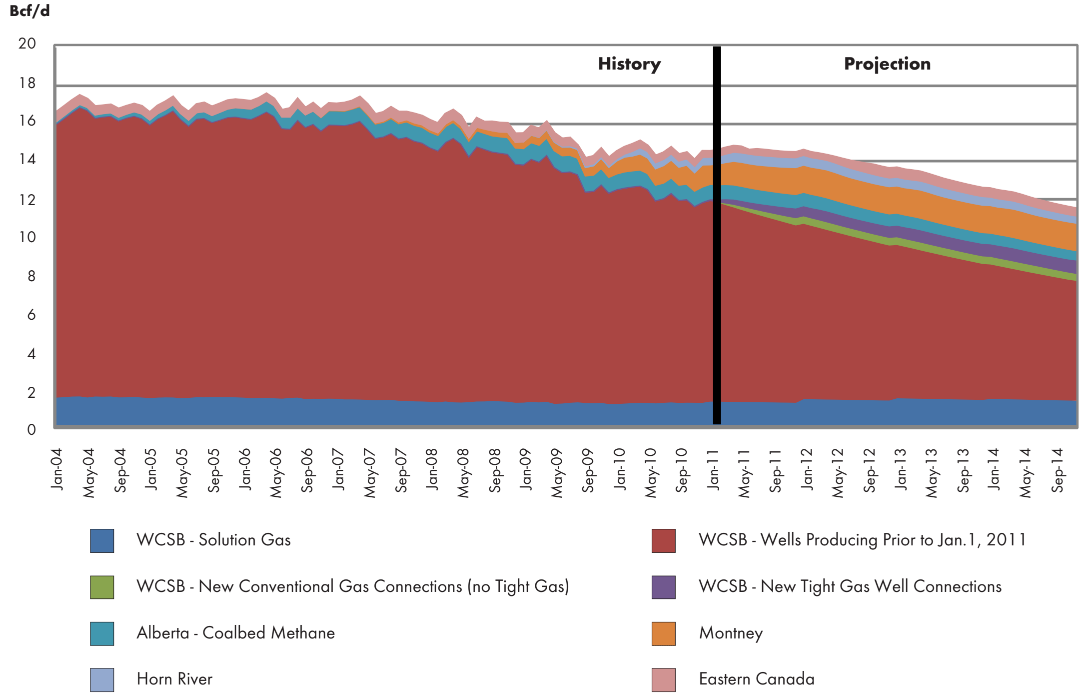
C.3 - Canadian Gas Deliverability by Area/Resource – Lower Price Case

Area/Resource	Historical				Projection					
	2010		2011*		2012		2013		2014	
	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d	$10^6m^3/d$	MMcf/d
00 - Alberta CBM	23.0	812	22.0	777	20.4	719	18.4	651	16.8	593
HSC Portion	17.9	633	16.9	598	15.5	548	14.0	494	12.6	446
Mannville Portion	3.0	107	2.9	104	2.9	101	2.6	92	2.4	85
Other CBM Portion	2.0	72	2.1	75	2.0	70	1.8	65	1.7	61
01 - Southern Alberta	38.4	1,355	36.1	1,274	31.6	1,115	26.8	948	22.8	805
Tight Portion	25.1	885	23.9	843	20.7	729	17.5	617	14.9	525
02 - Southwest Alberta	8.0	283	7.4	262	6.7	236	5.8	204	5.0	176
Tight Portion	2.3	82	2.2	76	1.9	66	1.6	55	1.3	47
03 - Southern Foothills	4.6	163	4.7	166	4.1	144	3.5	124	3.0	108
04 - Eastern Alberta	18.8	662	17.1	603	16.4	579	15.8	557	15.0	528
Tight Portion	0.4	15	0.4	14	0.3	12	0.3	10	0.2	9
05 - Central Alberta	22.3	787	20.4	721	19.0	671	17.6	620	15.9	560
Tight Portion	1.9	68	1.8	63	1.7	60	1.6	56	1.5	52
06 - West Central Alberta	44.6	1,574	43.9	1,549	43.7	1,544	40.6	1,433	36.7	1,296
Tight Portion	15.0	528	14.7	519	13.6	481	11.8	416	9.9	350
07 - Central Foothills	23.0	814	21.2	747	18.4	651	15.9	562	13.8	486
Tight Portion	1.3	45	1.2	41	1.0	36	0.8	30	0.7	25
08 - Kaybob	23.0	813	21.7	767	21.1	747	19.0	670	16.3	575
Montney Portion	2.9	104	3.1	108	3.5	123	3.4	120	3.0	106
Other Tight Portion	7.4	261	6.7	238	6.2	220	5.5	194	4.7	165
09 - Alberta Deep Basin	59.0	2,082	57.0	2,014	56.1	1,981	53.3	1,882	50.6	1,787
Montney Portion	2.5	88	3.0	105	3.8	133	4.6	161	5.4	191
Other Tight Portion	46.6	1,646	45.0	1,587	43.6	1,539	40.9	1,443	38.4	1,354
10 - Northeast Alberta	12.0	423	10.4	366	9.4	330	8.5	299	7.7	274
11 - Peace River	20.0	705	19.7	695	18.1	639	16.1	568	14.4	508
Tight Portion	6.2	219	6.3	221	5.4	192	4.8	168	4.2	148
12 - Northwest Alberta	10.6	374	9.2	326	8.2	289	7.0	246	5.7	202
Tight Portion	0.0	1	0.0	1	0.0	1	0.0	1	0.0	1
13 - BC Deep Basin	16.0	564	19.1	675	18.5	652	16.8	594	15.9	561
Montney Portion	1.9	69	2.2	79	2.3	81	1.7	59	1.4	49
Other Tight Portion	11.1	392	13.0	460	11.6	410	10.0	355	8.8	312
14 - Fort St. John	34.0	1,199	45.8	1,618	50.8	1,793	52.0	1,834	52.8	1,863
Montney Portion	18.1	640	27.7	976	34.2	1,209	37.0	1,305	39.3	1,386
15 - Northeast BC	15.9	563	19.8	698	19.3	681	17.8	630	15.6	549
Horn River Shale Portion	8.7	306	14.0	495	14.0	494	13.1	462	11.4	401
Tight Portion	5.7	200	4.3	153	4.0	142	3.6	128	3.2	114
16 - BC Foothills	16.0	566	17.2	607	15.2	538	13.3	468	11.5	407
Tight Portion	3.4	119	4.9	174	4.2	150	3.6	128	3.1	110
17 - Southwest Saskatchewan	8.1	285	6.8	239	5.9	210	5.1	180	4.4	155
Tight Portion	7.5	264	6.3	221	5.4	192	4.6	162	3.9	138
18 - West Saskatchewan	4.1	146	3.8	134	3.5	122	3.1	110	2.8	100
19 - East Saskatchewan	2.0	71	2.1	74	2.4	85	2.5	88	2.5	90
22 - Yukon and North West Territories	0.6	20	0.5	17	0.4	15	0.4	13	0.3	11
Total Conventional (no tight, no solution gas)	**176.4**	**6,228**	**165.6**	**5,845**	**149.9**	**5,293**	**132.0**	**4,659**	**116.1**	**4,098**
Total Tight	**159.3**	**5,624**	**166.5**	**5,876**	**163.6**	**5,775**	**153.2**	**5,409**	**143.9**	**5,080**
Montney Portion	**25.5**	**901**	**35.9**	**1269**	**43.8**	**1545**	**46.6**	**1646**	**49.0**	**1731**
Total Solution Gas	**36.6**	**1292**	**37.9**	**1337**	**41.3**	**1459**	**42.5**	**1499**	**41.4**	**1460**
Total CBM	**23.0**	**812**	**22.0**	**777**	**20.4**	**719**	**18.4**	**651**	**16.8**	**593**
Total Shale	**8.7**	**306**	**14.0**	**495**	**14.0**	**494**	**13.1**	**462**	**11.4**	**401**
Total WCSB	**404.0**	**14,262**	**405.9**	**14,330**	**389.2**	**13,740**	**359.2**	**12,681**	**329.5**	**11,632**
Atlantic Canada	8.9	313	7.6	269	9.9	350	12.6	444	11.1	392
Other Canada	0.5	16	0.5	16	0.4	15	0.4	14	0.4	14
Total Canada	**413.3**	**14,592**	**414.0**	**14,615**	**399.6**	**14,105**	**372.2**	**13,139**	**341.0**	**12,038**

*matched to 2011 actual production for January – August.

FIGURE C3

Outlook for Canadian Gas Deliverability – Lower Price Case

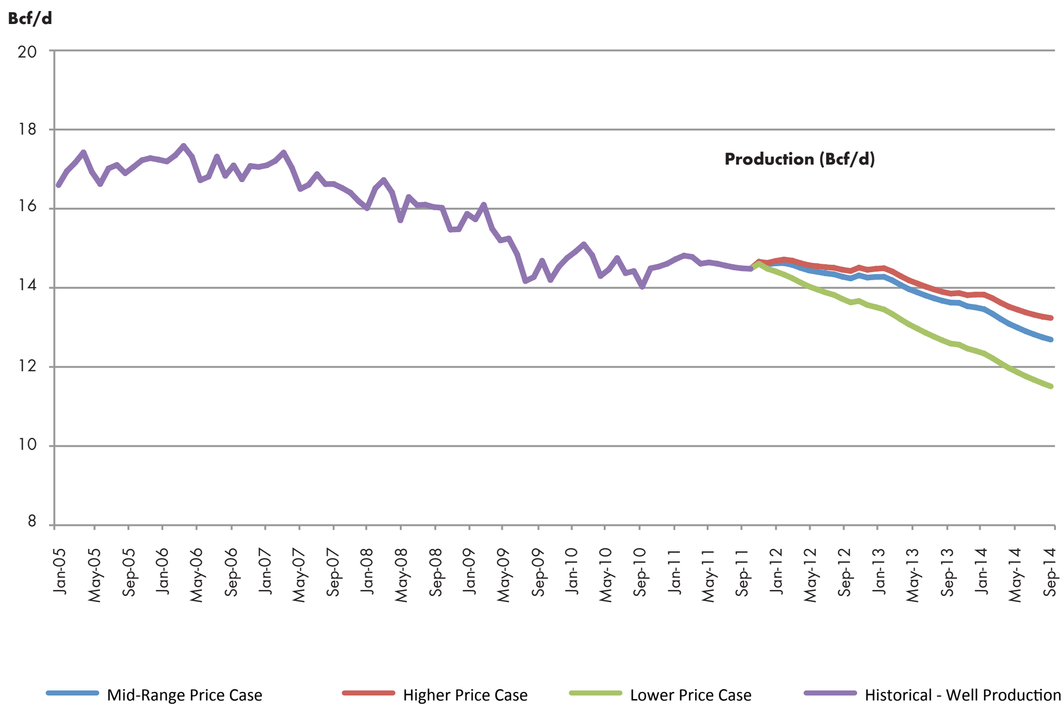


APPENDIX D

Total Canadian Deliverability Comparison by Case

FIGURE D1

Total Canadian Deliverability Comparison by Case



APPENDIX E

Average Annual Canadian Deliverability and Demand

E.1 – Average Annual Canadian Deliverability and Demand

	2011		2012		2013		2014	
	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$	Bcf/d
Canadian Deliverability, Mid-Range Case	414.0	14.6	409.9	14.5	396.8	14.0	372.8	13.2
Total Canadian Demand	252.1	8.9	260.6	9.2	266.3	9.4	277.6	9.8
Western Canada Demand	147.3	5.2	153.0	5.4	155.8	5.5	164.3	5.8
Eastern Canada Demand	104.8	3.7	107.6	3.8	110.5	3.9	113.3	4.0


-10
-20
-30
-40
-50
20
30
40
50
°F
°C

REDACTED

Request IR-122:

Regarding NS Power 2013 GRA Exhibit SR-03, the exhibit reports that, for natural gas prices, NSPI used the price strip from NYMEX for prices [redacted], plus broker quotes for the [redacted], for both 2013 and 2014. In reviewing information in NSPI's Confidential Data Room on parameters and assumptions for the fuel forecasts in the rate case (Binders No. GE-0034 for 2013 information, and GE-0035 for 2014), Liberty observed that the same source provided quotes for basis to [redacted]. With respect to that information:

a. Is the nature of those quotes different from that of the quotes [redacted] that the Company used in preparing its fuel-cost estimates for 2013 and 2014?

b. If the [redacted] quotes, how are they different?

c. Are the prices quoted by the broker the fixed-price side of a fixed-for-floating swap?

(i) [redacted]

(ii) [redacted]

(iii) [redacted]

d. If the prices quoted are not the fixed-price side of a fixed-for-floating swap, what are they:

i. [redacted]

ii. [redacted]

iii. [redacted]

e. If the quoted prices are for derivative financial instruments, such as fixed-for-floating swaps: (a) how do those instruments settle; i.e., settlement of a fixed-for-floating swap generally involves obtaining a price from a transaction, and (b) what is the nature of the transactions that provide the prices for the settlement of the derivatives?

f. If someone can transact [redacted] at the prices quoted by the broker, can NSPI not also transact at those prices at those locations?

g. If not, why not?

REDACTED

Response IR-122:

(a-g) The back-office provides the prices that are included in FAM Confidential Data Room Binders GE-0034 and GE-0035. The [redacted] are forecast prices provided by Platts. The prices for [redacted] are derived by the back-office. They are calculated by subtracting the applicable tolls and fuel from the forecast [redacted]. As these are derived prices, the market does not trade at these points.

REDACTED

Request IR-123:

2013 GRA Exhibit OE-01A, Attachment 1, is the financial report for the 2013 fuel forecast. This forecast is due to be updated with more-current information on or about August 31, 2012. Please provide an alternative case to the updated forecast that is the same in all respects as the updated fuel forecast <u>except</u> that the natural gas price for all NSPI gas purchases, including purchases of gas currently under contract, should be the [redacted]. Use the same source for the [redacted].

Response IR-123:

NS Power's fuel forecasts are performed in accordance with the FAM Plan of Administration, which specifies that the pricing will be based on the appropriate contractual point, which [redacted] The [redacted] price is derived from the [redacted] and it is not traded in the market.

REDACTED

Request IR-124:

2013 GRA Exhibit OE-01A, Attachment 4, is the financial report for the 2014 fuel forecast. This forecast is due to be updated with more-current information on or about August 31, 2012. Please provide an alternative case to the updated forecast that is the same in all respects as the update fuel forecast <u>except</u> that the natural gas price for all NSPI gas purchases, including purchases of gas currently under contract, should be the [redacted]. Use the same source for the [redacted].

Response IR-124:

Please refer to Liberty IR-123.

NON-CONFIDENTIAL

Request IR-125:

The Company's response to Liberty IR-25 in this proceeding refers to its response to Avon IR-17. Avon IR-17 refers to Avon IR-13. Avon IR-13 notes that "the procurement plan for biomass fuel is under development."

- **a. When will it be completed?**
- **b. Does the Company expect that its planning for and procurement of biomass fuel for the Port Hawkesbury biomass plant will be subject to review for prudence in the next FAM Audit?**
- **c. If not, why not?**

Response IR-125:

(a) NS Power expects that its procurement plan will be subject to continuing review and updating in order to ensure appropriate fuel is available on site in time for the commissioning processes. NS Power has engaged a biomass expert who is assisting with the development of a Request for Proposal (RFP) after engagement of potential suppliers.

(b) Yes.

(c) Not applicable.

NON-CONFIDENTIAL

Request IR-126:

The Company's response to Liberty IR-28 in this proceeding contains the following statement, "Under the proposed Shared Services Agreement, NS Power will operate 95 percent of the shared services and carry out required maintenance, expensing the associated labour costs to the Partnership."

a. Please explain how the operations of the biomass generating facility will relate to the operations of the Partnership.

b. Who will determine which costs should be charged to the biomass plant, and which costs should be charged to the Partnership?

c. How will those determinations be made?

Response IR-126:

(a) The Port Hawkesbury Biomass generating station will produce steam which will be used both to generate electricity and to provide steam for the papermaking process. The shared services processes include but are not limited to demineralized process water and compressed air supply, which are required by both facilities

(b) With respect to the operation and maintenance of the identified shared services, the "Shared Service Agreement" details which costs are charged to NS Power, and which costs are charged to the Partnership.

(c) Determination of responsibilities is detailed in the Shared Service Agreement using operating responsibilities and maintenance activities as the key demarcation criteria.

Request IR-127:

The Company's response to Liberty IR-29 in this proceeding attaches (Attachment 1) a Subcontract Assignment Agreement. In return for release of the Subcontractor's lien, the Company promises to pay for Equipment and Services as set out in Schedule "B".

- **a. Did NSPI pay NewPage Port Hawkesbury Corp. for any of those Equipment and Services?**
- **b. If so, which ones, and what was the amount of the payments?**
- **c. What is the Company doing to recover any payments that it made to NewPage Port Hawkesbury Corp. for Equipment and Services, including those in Schedule "B" of the Subcontract Assignment Agreement, for which it will have to pay the Subcontractor again?**

Response IR-127:

(a-c) NS Power did not pay NewPage Port Hawkesbury Corp. for any Equipment or Services under Schedule B of the Subcontract Assignment Agreement.

NON-CONFIDENTIAL

Request IR-128:

The Company's response to Liberty IR-29 in this proceeding attaches (Attachment 1) a Subcontract Assignment Agreement. In return for release of the Subcontractor's lien, the Company promises to pay for Equipment and Services as set out in Schedule "B". Schedule "B" includes two purchase orders, and "Change Orders Not Yet Approved".

a. What are those items for?

b. Does the Company expect to include those items in its rate base for this project?

Response IR-128:

(a) PO 4550466084 was for emissions dispersion modelling and PO 4550465759 was for a geotechnical program to determine subsurface conditions. The "Change Orders Not Yet Approved" included those scope changes for which AMEC had not received approval from NewPage at the time of the Companies' Creditors Arrangement Act (CCAA).

(b) To the extent the project cost does not exceed the approved Capital Work Order (CWO), the Purchase Orders (POs) and Change Orders, approved by NS Power, the costs will be included in rate base.

NON-CONFIDENTIAL

Request IR-129:

The Company's response to Liberty IR-37 in this proceeding refers to Avon IR-6. The response to Avon IR-6 includes an attachment (Attachment 1) entitled "Power Production Transformation Strategy".

a. Please provide the date that the Attachment was prepared.

b. Please provide the approximate dates when the Strategist Dispatch Optimization analysis referenced at page 8 of the Attachment was conducted.

c. Please confirm the footnotes on page 8 of the Attachment:

i. Fuel Pricing is per the IRP Base Case Refresh

ii. Load is 2012 GRA refresh load forecast (the most recent load forecast)

iii. DSM is ENSC Base Case DSM as of Oct 2011

d. Please compare the vintage of the fuel pricing in the analysis with the vintage of

i. The load forecast "(the most recent load forecast)"

ii. Estimated DSM ("Oct 2011")

e. Please compare the fuel pricing in the analysis with fuel-price forecasts that most closely match the vintages of the load forecast and the DSM forecast used in the analysis.

Response IR-129:

(a) The attachment was prepared November through December 2011.

(b) Strategist analysis was conducted between November 17, 2012 and January 26, 2012.

(c-d) Footnotes in page 8 of the attachment confirms:

(i) Fuel pricing is as of October 2011.

(ii) Load forecast is as of August 2011.

NON-CONFIDENTIAL

(iii) Demand Side Management (DSM) forecast is as of October 2011.

(e) Fuel, load and DSM forecasts are of the same vintage, and were the most recent forecasts available at the time of the study.

REDACTED

Request IR-130:

Refer to NSPI's response to Liberty IR-35 which requested a comparative analysis of cuts in programs and NSPI reference to its response to Liberty IR-55. With regard to <u>2012</u> activity, shown on NSPI's Confidential response to Liberty IR-55 Attachment 1 Page 1 of 1, please explain how each of the following items listed on the attachment supports NSPI's statement as it relates to program cuts in 2012.

- **a. Power Production [redacted] reduction noting only continuous improvement.**
- **b. Customer Operations which merely reflects a [redacted] reduction storm response and vegetation management, respectively; the same values requested as an increase in the prior GRA filing.**
- **c. No listed reductions in Customer Service, Technical & Construction Services, and Corporate Support Group.**
- **d. Sustainability reduction of [redacted] for reduced consulting services without any detail explanation – see also GRA DE-03 – DE-04 Appendix E page 25 which merely notes consulting decrease due to less activity.**

Response IR-130:

(a) NS Power's Power Production group hired consultants between 2010 and 2012 to assist with developing and implementing a maintenance continuous improvement program. The reduction in Operating, Maintenance and General (OM&G) is a reflection of the estimated savings for 2012.

(b) The 2012 GRA included additional amounts for storm response and vegetation management for Customer Operations.[1] All parties to the Settlement Agreement agreed

[1] NSPI 2012 General Rate Application, NSUARB-NSPI-P-892, May 13, 2011, DE-03-DE-04, page 9.

REDACTED

that these amounts would be removed from the 2012 costs included in the Application[2], which is reflected in the variance analysis. Additionally, pension costs increased by approximately [redacted], with reductions in the amounts allowed for wage increases and succession planning as agreed to in the 2012 GRA Settlement Agreement.[3]

(c) Customer Service costs overall increased [redacted] which included increased pension costs of [redacted] and cost reductions of [redacted]. Technical and Construction Services costs overall increased [redacted] which included increased pension costs of [redacted], labour cost reductions of [redacted] and other non-labour cost reductions of [redacted]. Corporate Support Group costs overall increased [redacted] which includes increased pension costs of [redacted], labour cost reductions of [redacted] and non-labour cost reductions of [redacted].

(d) The Sustainability Group has been involved in a range of activities as detailed in Avon IR-56. As plans are now in place to systematically achieve Renewable Electricity Standard (RES) Compliance through to 2015, the group is scaling back activity in a number of fronts and reducing expenditure. These include tidal development, biomass fuel development, wind development and carbon capture and storage.

[2] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011, page 2.
[3] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011, page 2.

CONFIDENTIAL (Attachment Only)

Request IR-131:

Refer to NSPI's response to Liberty IR-55 Attachment 1 Page 1 of 1. Please update the attachment to include a column which provides 2012 YTD Actual + budget remaining for each category listed.

Response IR-131:

Please refer to Partially Confidential Attachment 1.

Operating Cost by Group (in $M)

	2011A	2012F as filed in 2012 GRA (Note 1)	2012C Restated	[redacted]	Larger Variances	2013F		2014F		Larger Variances
						ΔSM	Δ%	ΔSM	Δ%	
Power Production	105.3	103.9	103.2	[redacted]	$4.1 Pension Increase	111.6		113.6		$5.4M Biomass Project,
					($1.0) Continuous Improvement	[redacted]		2.0	1.8	($4.1M) Lingan Transformation
Customer Operations	69.1	73.2	65.5	[redacted]	($3.7M) Storm Response, ($3.4M) Vegetation Management $1.0 Pension Increase	79.3		80.5		$5.5M Storm Response, $3.4M Vegetation Management
						[redacted]		1.2	1.5	
Customer Service	39.9	32.5	32.4	[redacted]		37.0		37.4		$2.0M Electric revenue write-offs and allowances for bad debt
					Pension Increase	[redacted]		0.4	1.1	
Technical & Construction Services	13.6	13.5	13.3	[redacted]		14.4		14.6		
						[redacted]		0.2	1.4	
Sustainability	3.2	2.0	2.0	[redacted]	($0.4) reduced consulting activity	1.5		1.5		
					($0.2) staff reductions	[redacted]		-	-	
Corporate Support Group	49.9	48.5	47.3	[redacted]		52.1		53.1		
						[redacted]		1.0	1.9	
Corporate Adjustments	(19.6)	(18.8)	(18.0)	[redacted]	$0.4 Admin. Overhead	(16.9)		(17.6)		$1.7M Workforce reduction ($1.6M) Administrative overheads (2013)
						[redacted]		(0.7)	(4.1)	($1.1M) Administrative overheads (2014)
Total	**261.4**	**254.8**	**245.7**	[redacted]						

Note 1 2012F as filed in 2012 GRA has been restated to reflect the reclassification of revenues previously included in operating costs to other revenues as required under US GAAP.
Note 2 NS Power has not produced a new 2012 budget; the budget remains as filed in the Application.

NON-CONFIDENTIAL

Request IR-132:

Refer to NSPI's response to Liberty IR-43. Please provide NSPI's actual earnings ratio for 2011 and 2012 YTD.

Response IR-132:

Please refer to Booth IR-3 Attachment 1 for the 2011 return on equity.

Return on equity is calculated based on actual year-end results. Therefore, there is no 2012 YTD calculation available.

NON-CONFIDENTIAL

Request IR-133:

Refer to NSPI's response to Liberty IR-52 and IR-69. Please provide a copy of all studies and related rationales on which NSPI relied for the development of level of non-union and union wage increases reflected in the filing for 2012 through 2014.

Response IR-133:

NS Power will provide this information to the Board upon request.

CONFIDENTIAL (Attachment Only)

Request IR-134:

Refer to NSPI's response to Liberty IR-72 and 75 regarding Succession Planning: (a) per the original request, please list the dollar values claimed as NSPI's ongoing request for succession planning for 2013 and 2014, and (b) to the extent such ongoing requirements are reflected within regular operating costs, please quantify said values related to succession planning by group, including a detailed breakdown of related staff number and associated dollars.

Response IR-134:

Please refer to Confidential Attachment 1 for a list of ongoing positions for succession planning and work force planning as filed in 2012 GRA Liberty IR-110[1] and updated for the Settlement Agreement.[2] No change is requested in this Application from what is already in rates as approved in the 2012 GRA.

[1] NSPI 2012 General Rate Application, NSPI (Liberty) IR-110, NSUARB-NSPI-P-892, June 28, 2011.
[2] NSPI 2012 General Rate Application, Settlement Agreement, NSUARB-NSPI-P-892, September 19, 2011.

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Request IR-135:

Please:

a) indicate what, if any, consideration NSPI has given to offering early retirement packages to its more senior employees in an effort to minimize labour costs

b) to the extent such consideration was given; please provide all relevant information, studies, and reports considered by management to also include the hiring of replacement entry staff at lower wage/salary rates.

Response IR-135:

(a-b) NS Power's management reviews the Company's needs at all staffing levels required to run the utility's operations through workforce planning and takes action as necessary to hire or reduce staffing. NS Power has not offered an early retirement package as NS Power has a workforce planning initiative which ensures proper succession planning to align with anticipated retirements so that knowledge transfer occurs effectively.

NS Power currently has 103 employees in workforce planning roles including Power Engineer Apprentices, Powerline Technician Apprentices, Engineers in Training and other various technical apprentice roles, each of whom are hired at a lower salary than a senior candidate.

NON-CONFIDENTIAL

Request IR-136:

Please update the table below to reflect the actual number of monthly retirements from July 1, 2011 to date. By way of background NSPI provided the information in the prior rate case proceeding and the amount listed in July 2012 was as of July 1, 2011.

Month	# of Retirements
2011	
January	6
February	3
March	4
April	5
May	1
June	4
July	10
August	
September	
October	
November	
December	
Total 2011	
2012	
January	
February	
March	
April	
May	
June	
July	
Total 2012	

Response IR-136:

Please refer to the updated figure below.

NON-CONFIDENTIAL

Month	# of Retirements
2011	
January	6
February	3
March	4
April	5
May	1
June	4
July	10
August	5
September	5
October	5
November	6
December	1
Total 2011	55
2012	
January	8
February	1
March	18
April	3
May	7
June	5
July	10
Total 2012	**52**

REDACTED

Request IR-137:

In the prior rate case proceeding NSPI provided information related to the number of eligible employees to retire by year and the number of employees retired as of July 1, 2011. The table provided is shown below. Please update the table to reflect amounts as of July 1, 2012.

Year	Eligible to Retire	Retired as of July 1/11	% Retired	Employees Still Active	% Eligible still Active
2001-2005	[redacted]				
2006	[redacted]				
2007	[redacted]				
2008	[redacted]				
2009	[redacted]				
2010	[redacted]				
2011	[redacted]				
Total	[redacted]				

Note: 2011 Retirements are YTD retirements as of July 1, 2011

Response IR-137:

For an updated table as of July 1, 2012 please refer to the figure below. The figures relate only to employees who are eligible for an unreduced pension.

Year Member Became Eligible for an Unreduced Pension	Eligible to Retire	Retired as of July 1/12*	% Retired	Employees Still Active	% Eligible Still Active
2006	[redacted]				
2007	[redacted]				
2008	[redacted]				
2009	[redacted]				
2010	[redacted]				
2011	[redacted]				
2012 (to July 1)	[redacted]				

[redacted].

*Includes those who died before retirement and data adjustments.

REDACTED

Request IR-138:

In the prior rate case proceeding NSPI provided information related to the number of eligible employees to retire with an unreduced pension by year and the corresponding number of employees retired as of July 1, 2011. The table provided is shown below. Please update the table to reflect amounts as of July 1, 2012.

Calendar Year Member Became Eligible to Retire with an Unreduced Pension	Count	Retired 2006	Retired 2007	Retired 2008	Retired 2009	Retired 2010	Retired 2011	Other Adjustments (Death, Data, etc)	Still Employed by NSPI
2005 and earlier	[redacted]								
2006									
2007									
2008									
2009									
2010									
2011									
Total									

[redacted]

Response IR-138:

Please refer to the figure below.

Calendar Year Member Became Eligible to Retire with an Unreduced Pension	Count	Retired 2006	Retired 2007	Retired 2008	Retired 2009	Retired 2010	Retired 2011	Retired 2012 (as of June 30th)	Other (Death, Data, etc.)	Still Employed by NSPI
2005 and earlier	[redacted]									
2006	[redacted]									
2007	[redacted]									
2008	[redacted]									
2009	[redacted]									
2010	[redacted]									
2011	[redacted]									
2012	[redacted]									
Total	[redacted]									

[redacted]

REDACTED

Request IR-139:

In the prior rate case proceeding NSPI provided a chart which reconciled members eligible for an unreduced pension by year from January 1, 2006 to July 31, 2011. The table provided is shown below. Please update the table to reflect amounts as of July 1, 2012.

Calendar Year	Total Eligible for unreduced retirement pension at start of year	Additional Members expected to be eligible for unreduced pension in calendar year	Retired with unreduced pension in first calendar Year eligible	Other retirements with unreduced pension (became eligible prior to current year)	Adjustments (deaths before retirement, data changes, etc)	Total Eligible for unreduced pension at end of Year
2006	[redacted]					
2007						
2008						
2009						
2010						
2011 (to July 31)						

Response IR-139:

Please refer to the figure below.

Calendar Year	Total Eligible for unreduced retirement pension at start of year	Additional Members expected to be eligible for unreduced pension in calendar year	Retired with unreduced pension in first calendar Year eligible	Other retirements with unreduced pension (became eligible prior to current year)	Adjustments (deaths before retirement, data changes, etc.)	Total Eligible for unreduced pension at end of Year
2006	[redacted]					
2007						
2008						
2009						
2010						
2011						
2012 (to July 1)						

NON-CONFIDENTIAL

Request IR-140:

In NSPI's prior rate case filing in response to Liberty IR-122, NSPI described its workforce planning initiative as follows, "NSPI has a workforce planning initiative which ensures proper succession planning to align with anticipated retirements so that knowledge transfer occurs effectively. As of March 31, 19 2011, there are 182 employees eligible to retire by December 31, 2011." NSPI further stated that, "NSPI currently has 169 employees in workforce planning roles including Power Engineer Apprentices, Powerline Technician Apprentices and Engineers in Training, each of whom are hired at a lower salary than a senior candidate." Similar to the preceding request, please update the number of employees eligible to retire by December 31, 2012 and provide the number of employees in workforce planning roles.

Response IR-140:

Please refer to Liberty IR-135.

NON-CONFIDENTIAL

Request IR-141:

Please: (a) identify the NSPI employees shown in the Retirements section of the confidential response to Liberty IR-80 who became employees or contractors of an affiliate within 3 months of resignation date, and (b) identify the affiliate in each case.

Response IR-141:

(a-b) NS Power does not track the employment activity of its retired employees.

NON-CONFIDENTIAL

Request IR-142:

The response to Liberty IR-80 contained a table showing New Hires into Permanent Roles; please identify the portion of IR-80 to which that information responds.

Response IR-142:

Liberty IR-80 requested various information regarding the departures and entry of employees into Nova Scotia Power. Based upon the request for information, the additional data was provided to assist with identifying the other means of obtaining employment with Nova Scotia Power.

NON-CONFIDENTIAL

Request IR-143:

Liberty IR-80 requested information through 2012 YTD; the response provided information only through 2011 for employee transfers. Please either confirm that there have been no transfers between NSPI and affiliates in 2012, or provide the information requested.

Response IR-143:

Transfers from NS Power to Affiliates in 2012 was shown on page 2 of Liberty IR-80 Attachment 1. As of the report date (May 31, 2012), there had been six transfers from NS Power to affiliates.

Transfers from affiliates to NS Power in 2012 was shown on page 3 of Liberty IR-80 Attachment 1. As of the report date, five employees had transferred from affiliates into NS Power.

NON-CONFIDENTIAL

Request IR-144:

Please confirm that NSPI will make available for on-site inspection at NSPI's offices the salary information for the positions identified in the confidential attachment to IR-80.

Response IR-144:

The salary paid to employees who have left NS Power and their new employer is confidential as between the employee and their new employer.

REDACTED

Request IR-145:

Please provide: (a) the typical costs (arranged to the maximum level possible by job level or type) typically applicable for recruitment services used to secure new employees, and (b) the annual internal total costs (personnel costs fully loaded) borne by NSPI for bringing in new NSPI employees.

Response IR-145:

(a) Outsourced recruitment services typically cost between [redacted]. In most cases NS Power does not use outsource recruitment services as it is handled internally.

(b) Recruitment and onboarding of new employees is a significant part of total Human Resources (HR) costs incurred throughout the Company outlined in Appendix E, Page 11 of 57 of the Application. This activity is not tracked separately from other HR services provided to existing employees.

NON-CONFIDENTIAL

Request IR-146:

With respect to the reports of NSPI's consultant benchmarking compensation for each of the comparator groups (Select, Regulated, Broad) and for each report filed with the UARB from 2010 through 2012, please provide the consultant's data showing: (a) the minimum and maximum revenues of group members, (b) the median revenues of the group, and (c) the consultant's source for the revenues.

Response IR-146:

(a-b) Revenue scope data for privately-held or subsidiary companies are not available in a public form and therefore Towers Watson is unable to provide the minimum, maximum, and median revenue data for each company as the data for privately-held or subsidiary companies are confidential and proprietary in nature. As a condition of participation, anonymous/aggregated data results can only be shared with participants of Towers Watson's Compensation Data Bank and cannot be shared in a public forum. Releasing these data will cause competitive harm to Towers Watson and impact Towers Watson's ability to maintain a compensation database and service clients.

(c) Revenues for organizations in the comparator groups are provided by each organization directly to Towers Watson during their annual surveying process.

NON-CONFIDENTIAL

Request IR-147:

The January 2009 consultant's executive compensation report filed with the UARB used size adjusted data where it found a relationship between revenue responsibility and pay. Please explain: (a) the consultant's standard for determining whether such a relationship exists, (b) why the consultant chose to do so for this position, (c) why it did not do so for other positions, and (d) whether there was or was not such a relationship with respect to other positions.

Response IR-147:

(a) Size adjusting data is a component of Towers Watson's standard methodology used in all competitive compensation reviews and is based on a standard logarithmic regression model used to test the relationship between any two variables. The regression model is applied separately to each position, and predicts where a correlation or relationship exists between executive pay and position scope.

(b) Where data was size adjusted for a particular position, it was because Towers Watson's standard logarithmic regression model determined that a relationship existed between executive pay and position scope, and that the size adjusted data more appropriately reflected the scope of NS Power's role than the raw data results.

(c) Towers Watson did not provide size adjusted data where a relationship between pay and position scope did not exist.

(d) Towers Watson provided size adjusted data where data was sufficient and a strong correlation between pay and position scope existed. For all positions, Towers Watson evaluated the appropriateness, sufficiency and scope of raw data results, and provided these results where it was determined to be an appropriate comparison for NS Power's roles.

Request IR-148:

The January 22, 2010 consultant's executive compensation report filed with the UARB used regression analysis for the EVP & COO, "where there was a relationship between revenue responsibility and pay" but did not do so for other positions; please explain: (a) the consultant's standard for determining whether such a relationship exists, (b) why the consultant chose to do so for this position, (c) why it did not do so for other positions, and (d) whether there was or was not such a relationship with respect to other positions.

Response IR-148:

(a) Please refer to Liberty IR-147(a).

(b) Data for the EVP (Executive Vice President) & COO (Chief Operating Officer) was size adjusted because Towers Watson's standard logarithmic regression model determined that a relationship existed between executive pay and position scope, and that the size adjusted data more appropriately reflected the scope of NS Power's role than the raw data results.

(c) Please refer to Liberty IR-147(c).

(d) Please refer to Liberty IR-147(d).

NON-CONFIDENTIAL

Request IR-149:

The January 22, 2010 consultant's executive compensation report filed with the UARB also used a Broad group (revenue between $500 million and $2 billion) for positions with "insufficient data." Please explain the consultant's criteria used to determine whether data was insufficient.

Response IR-149:

Towers Watson's standard methodology provides percentile distributions (25^{th}, 50^{th} and 75^{th}) only where there are at least five data points. 50^{th} percentile (median) data are provided where there are at least four data points. To protect the confidentiality of Tower Watson's client data, data are considered 'insufficient' where there are fewer than four data points.

NON-CONFIDENTIAL

Request IR-150:

The January 22, 2010 consultant's executive compensation report filed with the UARB also used data from all survey participants for two positions (VP Commercial Ops and EVP Sustainability) Please: (a) explain the consultant's rational for using such data for those positions, (b) explain the consultant's reasons for not using such for other positions, and (c) provide the consultant's data on what the minimum, maximum, and median revenues are for the all survey participants group were.

Response IR-150:

(a) Data for the Executive Vice President Sustainability was sourced from all survey participants due to insufficient data in each of the Select Comparators sample and general industry sample of companies with revenue between $500 million and $2 billion. Furthermore, as noted on page 6 of the Executive Compensation Review, data for the Vice President Commercial Operations was drawn from the general industry sample due to insufficient data in the Select Comparators sample.

(b) Companies in the Select Comparator group were chosen for their industry relevance and serve as the most direct comparators for NS Power. Accordingly, data from the Select Comparator group was used as the basis for making primary comparisons to NS Power. As note on page 6 of the Executive Compensation Review, where there were insufficient data for the Select Comparators, the sample was expanded to include companies from general industry.

(c) Revenue scope data for privately-held or subsidiary companies are not available in a public form and therefore Towers Watson is unable to provide the minimum, median and maximum revenue data for each company as the data for privately-held or subsidiary companies are confidential and proprietary in nature. As a condition of participation, anonymous/aggregated data results can only be shared with participants of Towers Watson’s Compensation Data Bank and cannot be shared in a public forum. Releasing these data will cause competitive harm to Towers Watson and impact Towers Watson’s ability to maintain a compensation database and service clients.

REDACTED

Request IR-151:

Please note that IR 151 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please provide the initially requested response to IR-2.c. To further clarify, the following table shows the differences between OE-01J and OE-01E for 2014 which you did not explain, especially since you are stating that the quantities under contract are the same as the quantities hedged:

Quantities (MT)	**OE-01E**	**OE-01J**
Contracted	[redacted]	
Open		
Total		

Response IR-151:

In 2014, NS Power has an open position for domestic coal which was excluded from the hedged position calculation as there are no financial instruments available to hedge domestic coal.

REDACTED

Request IR-152:

Please note that IR 152 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please provide the initially requested response to IR-6. Specifically, no mention is made anywhere of DE-03 in your response.

Response IR-152:

Please refer to the following addition to Liberty IR-6:

Reference: Table in Liberty IR-6 comparing data from DR-311 and data Appendix B Figure 1-1 of the Application:

Quantities (Thousands of Metric Tonnes)
[redacted]

The Portfolio presented in DR-311 was produced in December 2011. It was based on the following sources:

- The most recent FAM forecast that was available, which was the 2012 FAM forecast. This provided the data in DR-311 for year 2012.

REDACTED

- The most recent internal five-year estimate that was available when the December 31, 2011 portfolio was produced, which was Quarter 1 2011. This provided the data used in DR-311 for years 2013 and 2014.

The Portfolio presented in DE-03-DE-04 of the Application was produced in early 2012. It was based on the following sources:

- The most recent formal FAM forecasts available which were the GRA forecasts for 2013 and 2014. This provided the data used in the Application for years 2013 and 2014. This data is nearly a year newer, than the data used in DR-311 for these years.

Between the Quarter 1 2011 timeframe of the DE-311 data and the Q1 2012 timeframe of the Application data, load forecasts differed, including the absence of NewPage, and the relative pricing between coal and natural gas changed. These differences result in a lower forecast solid fuel requirement in the Application compared to DR-311.

NON-CONFIDENTIAL

Request IR-153:

Please note that IR 153 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please provide the initially requested response to IR-79(e) and (f). Specifically, please indicate which group, ratepayers or shareholders, will be funding this project, as well as the account to which the funds will be charged.

Response IR-153:

These costs are prudently incurred costs of procuring fuel for the benefit of customers. NS Power intends to seek recovery of these costs through the FAM. As noted, no costs have yet been paid incurred by NS Power. NS Power has not yet determined the account to which these costs will be charged. The benefits to customers associated with the lower cost of fuel that is able to be obtained as a result of this project is reflected in the Base Cost of Fuel forecast.

Request IR-154:

Please note that IR 154 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-15: With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), Exhibit 1, please revise the exhibit to show the following information for each LNG import terminal:

a. Location
b. Ownership
c. Re-gasification capacity
d. LNG storage capacity, in Bcf
e. Size of largest LNG tanker that the receiving facility can accommodate
f. Pipeline system connections (which pipelines).

Please organize the list into (1) those that are part of the Pacific Basin LNG Market, and (2) those that are part of the Atlantic Basin LNG Market.

Response IR-154:

(a-f) NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-155:

Please note that IR 155 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-16: for each of the LNG receiving facilities identified in the response to the previous question, please report its ownership by, or affiliation with, an owner of gas liquefaction facilities. Examples include Canaport, which is 75-percent owned by Repsol, S. A., which also owns liquefaction facilities, and the Golden Pass LNG Terminal, located near Sabine Pass, Texas, which is 70-percent owned by Qatar Petroleum International, which also either owns liquefaction facilities, or is affiliated with an owner of liquefaction facilities.

Response IR-155:

NS Power has not prepared this information as part of this Application.

Request IR-156:

Please note that IR 156 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-17: With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, Mr. Crook reports that "LNG trades can be characterized in two geographic markets: the Atlantic Basin and the Pacific Basin." Please provide the same information for the LNG receiving facilities in each of those two markets as is provided for the North American ones; i.e.:

a. Location
b. Ownership
c. Re-gasification capacity
d. LNG storage capacity, in Bcf equivalent
e. Size of largest LNG tanker that the receiving facility can accommodate
f. Pipeline system connections (which pipelines).

Please organize the list into (1) those that are part of the Pacific Basin LNG Market, and (2) those that are part of the Atlantic Basin LNG Market.

Response IR-156:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-157:

Please note that IR 157 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-18: For each of the LNG receiving facilities identified in the response to the previous question, please report its ownership by, or affiliation with, an owner of gas liquefaction facilities.

Response IR-157:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-158:

Please note that IR 158 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-19: With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, please provide lists of the LNG exporting facilities that serve the Atlantic and Pacific Basins, respectively. For each such facility please provide the following:

- **a. Location**
- **b. Ownership**
- **c. Liquefaction capacity, in Bcf/day**
- **d. LNG export capacity, in Bcf/day equivalent**
- **e. LNG storage capacity, in Bcf equivalent**
- **f. Size of largest LNG tanker that the facility can accommodate**
- **g. Source of supply**
- **h. Date of entry into service.**

Please organize the list into (1) those that serve the Pacific Basin LNG Market, and (2) those that serve the Atlantic Basin LNG Market.

Response IR-158:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-159:

Please note that IR 159 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-20: With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 9, please provide lists of the LNG exporting facilities that are expected to enter service in the next five years. Please organize the lists by year, and into those that serve the Atlantic and Pacific Basins, respectively. For each such facility please provide the following:

- **a. Location**
- **b. Ownership**
- **c. Liquefaction capacity, in Bcf/day**
- **d. LNG export capacity, in Bcf/day equivalent**
- **e. LNG storage capacity, in Bcf equivalent**
- **f. Size of largest LNG tanker that the facility can accommodate**
- **g. Source of supply**
- **h. Expected date of entry into service.**

Please organize the list into (1) those that serve the Pacific Basin LNG Market, and (2) those that serve the Atlantic Basin LNG Market.

Response IR-159:

NS Power has not prepared this information as part of this Application.

NON-CONFIDENTIAL

Request IR-160:

Please note that IR 160 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Regarding original IR-23: With respect to 2013 GRA DE-03 – 04 Appendix D (Testimony of Leonard Crook, ICF International), at page 11, please provide ICF's month-by-month (or seasonal) forecasts of the wholesale gas prices in 2013 and 2014 at the following trading hubs:

- **a. Dracut, MA**
- **b. Tennessee Gas Pipeline Zones 5 and 6**
- **c. Algonquin city gates**
- **d. Texas Eastern Market Zone 3**
- **e. Transco Zone 6, New York and non-New York.**

Response IR-160:

NS Power has not prepared this information as part of this Application and ICFI has not provided its Base Case Gas Market Model (GMM) gas price forecast to NS Power.

CONFIDENTIAL (Attachment Only)

Request IR-161:

Please note that IR 161 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Liberty IR-80 requested identification of the particular affiliate involved; please provide that information for each position shown in the confidential attachment to NSPI's response to that IR.

Response IR-161:

Please refer to Confidential Attachment 1. Please note that NS Power does not have employee transfer data for all Emera affiliates as we do not have all affiliate employees on the NS Power Human Resources system. Data has been provided for the following affiliate companies only; Emera, Emera Energy, Emera Utility Services (only some), Brunswick Pipeline, Emera Newfoundland, and Bayside.

NON-CONFIDENTIAL

Request IR-162:

Please note that IR 162 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 12 of 57. More specifically, refer to the $109,000 increase in external legal and audit due to collective bargaining activity (2011 actual vs. 2013 forecast). Please explain why there is no reduction in the 2014 Forecast period for such professional fees, given that the general history for NSPI negotiated union increase have provided for multiple year contract terms rather than just annual contracts.

Response IR-162:

The requested question was not asked in the first round of Information Requests.

This item was not removed in 2014 because it is expected that this amount, $142,000, escalated annually would reflect normal external legal and audit expenditures, although likely for items other than collective bargaining.

REDACTED

Request IR-163:

Please note that IR 163 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 14 of 57. More specifically, refer to the $405,000 increase in general cost recovery due to leases expiring (2012 compliance vs. 2013 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-163:

The requested question was not asked in the first round of Information Requests.

The $405,000 is a decrease of general cost recovery from $1,110,000 in 2012C to $705,000 for 2013F. This decrease should be viewed in relation to the increase in non-regulated cost recovery of $270,000. Please refer to the figure below for the explanation of the net decrease of $135,000. [redacted] with NS Power expired in March 2011. The forecast for 2013 assumed [redacted].

Recovery Item	2013F vs. 2012C (Thousands of $)
[redacted]	108
Cost escalation and Other Facilities	27
Total Decreased Recovery	**135**

This is a permanent change and as such is a go forward item.

NON-CONFIDENTIAL

Request IR-164:

Please note that IR 164 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 15 of 57. More specifically, refer to the $325,000 increase related to write-offs of inventory with implementation of work management system (2011 actual vs. 2013 forecast). Please: (a) explain why this expense write off was not removed from the 2014 Forecast period, and (b) confirm or correct Liberty's understanding that the claim as reflected would result in this claim being a normalized ongoing level of expense claim.

Response IR-164:

The requested question was not asked in the first round of Information Requests.

(a) This increase of $325,000 in write offs is reflective of a credit for write-offs in 2011 of $274,000 compared to the 2013 forecast expense of $51,000. During 2011, reconciliations of the inventories were conducted as part of the implementation of a new inventory system and adjustments to write offs were made to account for the physical counts observed. The 2013 forecast, of $51,000, escalated annually would reflect normal inventory shrinkage during the cycle count process at our facilities.

(b) Confirmed.

Request IR-165:

Please note that IR 165 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 15 of 57. More specifically, refer to the $343,000 increase described as General Cost recovery due to leases expiring and move to Lower Walter Street. Please provide all data supporting this amount as an annual going forward item.

Response IR-165:

The requested question was not asked in the first round of Information Requests.

The $343,000 is a decrease of general cost recovery from $1,048,000 in 2011 to $705,000 for 2013F. This decrease should be viewed in relation to the increase in non-regulated cost recovery of $355,000. Recoveries at the Lower Water Street location are similar in nature to recoveries at the Barrington Tower location, but are treated differently for account coding as NS Power owns the Lower Water Street facility. The net increase is $12,000.

REDACTED

Request IR-166:

Please note that IR 166 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 17 of 57. More specifically, refer to the $527,000 and $299,000 increases related to software in 2013 and 2014 forecast periods. Please provide all data supporting these amounts as an annual going forward item.

Response IR-166:

The requested question was not asked in the first round of Information Requests.

Software maintenance agreements are an ongoing annual expense to NS Power and relate to all software applications used within the business. New applications and/or incremental user licenses purchased to satisfy business requirements result in additional software maintenance expense annually. Expense projections for 2013 and 2014 reflect forecasts of these ongoing expense items. Please see figure below for details comparing 2013 forecast with 2012 Compliance forecast as well as 2014 forecast versus 2013 forecast.

REDACTED

033 Rental/Mtnce equipment/software	***2013 Forecast vs. 2012 Compliance***
	(Thousands of $)
[redacted]	
	$527
033 Rental/Mtnce equipment/software	***2014 Forecast vs. 2013 Forecast***
	(Thousands of $)
New applications, Additional users (Estimated to include, but not limited to [redacted]. Further upgrades to [redacted] expected in 2014.)	[redacted]
Escalation	49
	$299

REDACTED

Request IR-167:

Please note that IR 167 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 18 of 57. More specifically, refer to the $223,000 and [redacted] increases related to support for new software application, i.e., 2011 actual vs. 2013 forecast and 2012 forecast vs 2013 forecast. Please provide all data supporting these amounts as an annual going forward item.

Response IR-167:

The requested question was not asked in the first round of Information Requests.

Software maintenance agreements are an ongoing annual expense to NS Power and relate to all software applications used within the business. The maintenance variance for the requested periods includes a forecast increase in costs applied by the software vendors as well as maintenance costs associated with incremental licenses for applications such as Maximo and Oracle Financials. Please refer to the figure below for details of the [redacted] increase in costs from 2012 forecast to 2013 forecast. The 2013 forecast is planned based from the 2012 forecast. Expenses in 2011 were higher than the cost planning for 2012. The increase in costs of $223,000 between 2013 forecast and 2011 actuals is therefore due to the additional planning for 2013 partially offset by that 2011 actual experience of higher costs.

REDACTED

033 Rental/Mtnce equipment/software	**2013 Forecast vs. 2012 Forecast**
	(Thousands of $)
Additional Maximo Licences	[redacted]
Cisco/Bell	
Additional PI Licences	
Cognos	
Additional Oracle Licences	
Gartner Inc.	
Other (Service Hub, Itron, Fuelworx, etc)	
Escalation	

NON-CONFIDENTIAL

Request IR-168:

Please note that IR 168 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 23 of 57. More specifically, refer to the $189,000 increase described as Non-regulatory cost recovery increase due to no recovery forecasted in 2013 (2011 actual vs. 2013 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-168:

The requested question was not asked in the first round of Information Requests.

The non-regulatory cost recovery is related to work Technical and Construction Services employees, on a one-off basis, perform at the request and on behalf of an affiliate. This affiliate work is not forecasted in future years. This is not an annual going forward item. The associated labour costs were charged at cost plus 50 percent in compliance with the Affiliate Code of Conduct.

NON-CONFIDENTIAL

Request IR-169:

Please note that IR 169 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 25 of 57. More specifically, refer to the $103,000 increase described as advertising increase due to advertising for new initiative (2011 actual vs. 2013 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-169:

The requested question was not asked in the first round of Information Requests.

NS Power contemplated a number of activities designed to promote customer support, customer information, education, and awareness of technologies such as heat pumps. Please refer to Avon IR-56.

NON-CONFIDENTIAL

Request IR-170:

Please note that IR 170 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 27 of 57. More specifically, refer to the $569,000 increase described as consulting increase due to support of strategic asset planning (2011 actual vs. 2013 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-170:

Please refer to NSUARB IR-59.

NON-CONFIDENTIAL

Request IR-171:

Please note that IR 171 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 41 of 57. More specifically, refer to the $235,000 increase described as miscellaneous revenue and recoveries decrease due to less activity (2011 actual vs. 2013 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-171:

The requested question was not asked in the first round of Information Requests.

The $235,000 amount was relative to the 2011 year, which incurred a one-time increase in revenue due to a change in the timing of the recognition of the margin associated with performing feasibility studies for renewable energy applications. This was a one-time change that will not reoccur in future years.

NON-CONFIDENTIAL

Request IR-172:

Please note that IR 172 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 43 of 57. More specifically, refer to the $166,000 increase described as fleet fuel increase due to estimated increase in fuel prices activity (2013 forecast vs. 2014 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-172:

The requested question was not asked in the first round of Information Requests.

The increase in fleet fuel was estimated using escalators as outlined in CA IR-19, and was 6.15 percent for 2014 versus 2013. The increase in fuel price is not intended to represent an annual going forward item, but is an estimate of the increase in fuel price for that year.

NON-CONFIDENTIAL

Request IR-173:

Please note that IR 173 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 46 of 57. More specifically, refer to the $234,000 increase described as contracts increase due to cost escalation (2013 forecast vs. 2014 forecast). Please provide all data supporting this amount as an annual going forward item.

Response IR-173:

The requested question was not asked in the first round of Information Requests.

The increase in contracts was estimated using escalators as outlined in CA IR-19, and was 1.64 percent for 2014 versus 2013. The increase in the cost of contracts is not intended to represent an annual going forward item, but is an estimate of the change in the price of those services for that year.

NON-CONFIDENTIAL

Request IR-174:

Please note that IR 174 seeks information requested in Liberty's First Round of IRs but not included in NSPI's responses

Please refer to partially confidential 2013 GRA DE-03 – DE-04 Appendix E, page 56 of 57. More specifically, refer to the $207,000 increase related to write-offs of inventory (2012 compliance vs. 2013 forecast). Please: (a) explain why this expense write off was not removed from the 2014 Forecast period, and (b) confirm or correct Liberty's understanding that the requested rate increase would result in this amount being a normalized ongoing level of expense.

Response IR-174:

Write-offs of inventory are based on valuation models that review the age of inventory items and age of the plants that make use of that inventory. The level of expense planned for 2012F, 2013 and 2014 reflects management's best estimate on the ongoing level of expense and is projected lower than the 2010 actual experience and the 2011 actual experience. The expense is projected to be an ongoing level of expense.