

**THE ADDITION OF  
UNCONVENTIONAL NATURAL GAS SUPPLY  
TO GHGENIUS**

Prepared For:

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## EXECUTIVE SUMMARY

The GHGenius model has been developed for Natural Resources Canada over the past eleven years. It is based on the 1998 version of Dr. Mark Delucchi's Lifecycle Emissions Model (LEM). GHGenius is capable of analyzing the energy balance and emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels.

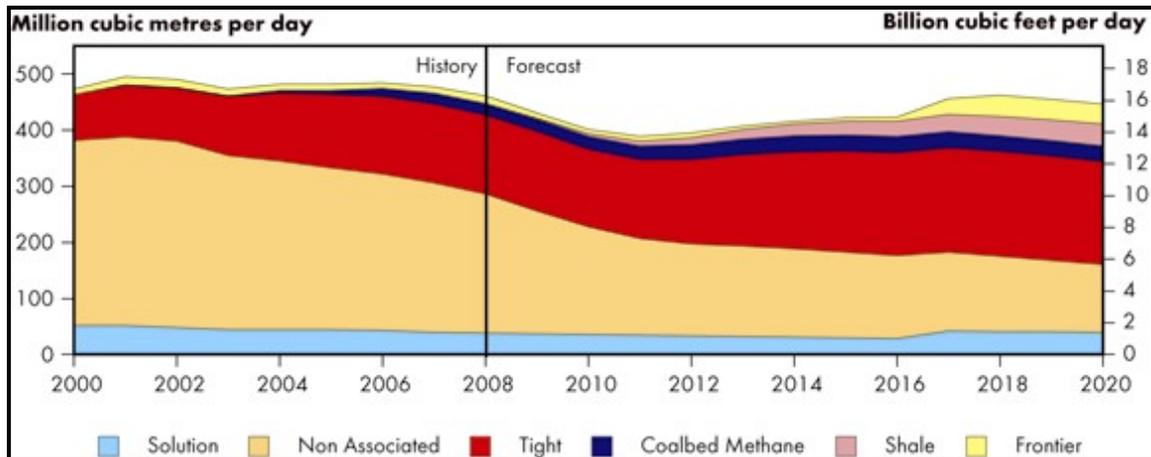
GHGenius is capable of estimating life cycle emissions of the primary greenhouse gases and the criteria pollutants from combustion and process sources. The specific gases that are included in the model include:

- Carbon dioxide (CO<sub>2</sub>),
- Methane (CH<sub>4</sub>),
- Nitrous oxide (N<sub>2</sub>O),
- Chlorofluorocarbons (CFC-12),
- Hydro fluorocarbons (HFC-134a),
- The CO<sub>2</sub>-equivalent of all of the contaminants above.
- Carbon monoxide (CO),
- Nitrogen oxides (NO<sub>x</sub>),
- Non-methane organic compounds (NMOCs), weighted by their ozone forming potential,
- Sulphur dioxide (SO<sub>2</sub>),
- Total particulate matter.

The model is capable of analyzing the emissions from conventional and alternative fuelled internal combustion engines or fuel cells for light duty vehicles, for class 3-7 medium-duty trucks, for class 8 heavy-duty trucks, for urban buses and for a combination of buses and trucks, and for light duty battery powered electric vehicles. There are over 200 vehicle and fuel combinations possible with the model.

Canadian production of conventional natural gas is declining and is expected to continue to decline over the next few years. The National Energy Board, in their latest forecast, sees coal bed methane, shale gas, and eventually frontier gas supplementing declining supplies of conventional gas and tight gas as shown in the following figure.

**Figure ES- 1 Forecast Natural Gas Supply**



The types of gas shown in the figure can be classified as follows:

- Solution gas is that which is dissolved in crude oil under pressure and is produced at the same time as crude oil is produced.
- Non associated gas is gas that is produced independently of crude oil production.
- Tight gas is gas stored in low-permeability rock. Tight gas reservoirs require artificial fracturing to enable the gas to flow.
- Coalbed methane (CBM) is a form of natural gas extracted from coalbeds. Coalbed methane is distinct from typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
- Shale gas is natural gas stored in organic rich rocks such as dark-coloured shale, interbedded with layers of shaley siltstone and sandstone. Shale can be the source, reservoir and the seal for the gas.
- Frontier gas in Canada is the gas from regions that the National Energy Board has authority over. It includes gas in the arctic and offshore areas in the Pacific and Atlantic oceans.

The data on natural gas production in the GHGenius model has been based on a weighted average of solution gas, non-associated, and tight gas.

The GHG emission profiles for these different sources of gas are likely to be significantly different from conventional gas. Each type of gas can have different energy requirements for extracting it, different compositions, and different methane leakage rates. Some of the shale gas deposits, for example, have CO<sub>2</sub> contents of 10 to 12% compared to a more typical level of 2% in conventional gas fields. These unconventional natural gas resources, coal bed methane and shale gas, comprise at least 15 per cent of estimated remaining natural gas resources in western Canada.

The goal of this work was to modify the natural gas pathways in GHGenius to accommodate these different sources of natural gas. The GHGenius user can now choose to model each type of natural gas individually or a blend of the different types of production. The data used for modelling these different sources of gas was not as well developed as the data for conventional gas and the model has been developed so that it is easy to change these inputs as better data become available.

GHGenius has been expanded so that it can model different types of natural gas production. All of the existing functionality of the model has been maintained. The proportion of each type of gas to the national gas pool is based on National Energy Board data and forecasts through to the year 2020. The GHG emissions results for the upstream portion of the lifecycle for each type of gas are shown in the following table.

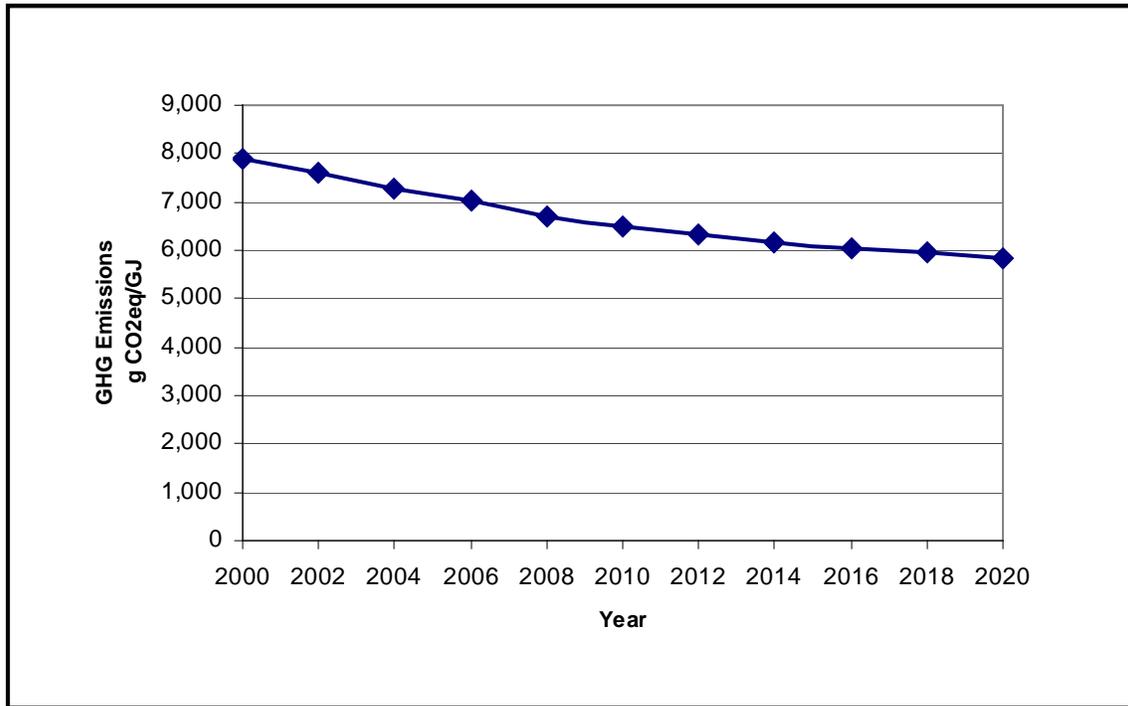
**Table ES- 1 Natural Gas Emissions by Type of Gas**

| Fuel   | Conventional Gas        | Coalbed Methane | Shale Gas | Tight Gas | Frontier Gas |
|--|-------------------------|-----------------|-----------|-----------|--------------|
| Use  | commerce                |                 |           |           |              |
|  | g CO <sub>2</sub> eq/GJ |                 |           |           |              |
| Fuel dispensing                                    | 0                       | 0               | 0         | 0         | 0            |
| Fuel distribution and storage                      | 1,303                   | 1,249           | 1,340     | 1,303     | 3,465        |
| Fuel production                                    | 1,377                   | 0               | 1,414     | 1,377     | 1,360        |
| Feedstock transmission                             | 0                       | 0               | 0         | 0         | 0            |
| Feedstock recovery                                 | 1,710                   | 1,663           | 1,742     | 1,710     | 1,697        |
| Land-use changes, cultivation                      | 0                       | 0               | 0         | 0         | 0            |
| Fertilizer manufacture                             | 0                       | 0               | 0         | 0         | 0            |
| Gas leaks and flares                               | 1,369                   | 1,029           | 1,369     | 1,369     | 1,373        |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 824                     | 0               | 2,473     | 824       | 0            |
| Emissions displaced                                | 0                       | 0               | 0         | 0         | 0            |
| Total  | 6,584                   | 3,941           | 8,338     | 6,584     | 7,895        |

The emissions from the combustion of natural gas are about 50,000 g CO<sub>2</sub>eq/GJ, depending on the combustion efficiency. The variation in the upstream emissions between the different types of natural gas would appear to be less than 10% of the lifecycle emissions for the production and use of the gas. However, there is significant uncertainty with respect to the energy and environmental performance of the emerging sources of gas and more work is warranted to better document the emissions of the new energy sources.

The emissions of the pool of natural gas over time are shown in the following figure. The emissions do trend downwards due primarily the assumptions in the model related to methane losses. As seen in the previous table, some sources of natural gas have lower emissions and other sources have higher emissions, and these two trends do have an offsetting impact.

Figure ES- 2 Upstream NG GHG Emissions



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# 1. INTRODUCTION

The GHGenius model has been developed for Natural Resources Canada over the past eleven years. It is based on the 1998 version of Dr. Mark Delucchi's Lifecycle Emissions Model (LEM). GHGenius is capable of analyzing the energy balance and emissions of many contaminants associated with the production and use of traditional and alternative transportation fuels.

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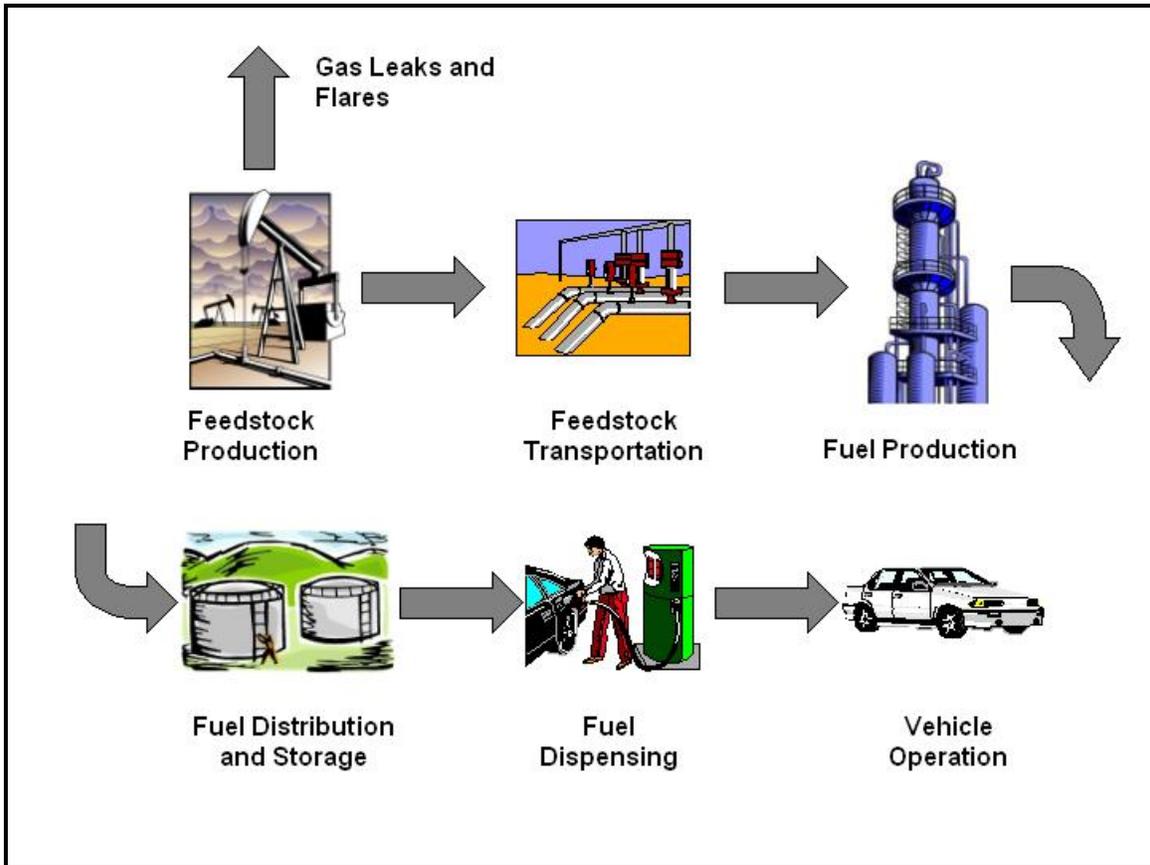
GHGenius can predict emissions for past, present and future years through to 2050 using historical data or correlations for changes in energy and process parameters with time that are stored in the model. The fuel cycle segments considered in the model are as follows:

- Vehicle Operation  
Emissions associated with the use of the fuel in the vehicle. Includes all greenhouse gases.
- Fuel Dispensing at the Retail Level  
Emissions associated with the transfer of the fuel at a service station from storage into the vehicles. Includes electricity for pumping, fugitive emissions and spills.
- Fuel Storage and Distribution at all Stages  
Emissions associated with storage and handling of fuel products at terminals, bulk plants and service stations. Includes storage emissions, electricity for pumping, space heating and lighting.
- Fuel Production (as in production from raw materials)  
Direct and indirect emissions associated with conversion of the feedstock into a saleable fuel product. Includes process emissions, combustion emissions for process heat/steam, electricity generation, fugitive emissions and emissions from the life cycle of chemicals used for fuel production cycles.
- Feedstock Transport

- Direct and indirect emissions from transport of feedstock, including pumping, compression, leaks, fugitive emissions, and transportation from point of origin to the fuel refining plant. Import/export, transport distances and the modes of transport are considered. Includes energy and emissions associated with the transportation infrastructure construction and maintenance (trucks, trains, ships, pipelines, etc.)
- Feedstock Production and Recovery  
Direct and indirect emissions from recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, upstream processing prior to transmission, and mining.
  - Fertilizer Manufacture  
Direct and indirect life cycle emissions from fertilizers, and pesticides used for feedstock production, including raw material recovery, transport and manufacturing of chemicals. This is not included if there is no fertilizer associated with the fuel pathway.
  - Land use changes and cultivation associated with biomass derived fuels  
Emissions associated with the change in the land use in cultivation of crops, including N<sub>2</sub>O from application of fertilizer, changes in soil carbon and biomass, methane emissions from soil and energy used for land cultivation.
  - Carbon in Fuel from Air  
Carbon dioxide emissions credit arising from use of a renewable carbon source that obtains carbon from the air.
  - Leaks and flaring of greenhouse gases associated with production of oil and gas  
Fugitive hydrocarbon emissions and flaring emissions associated with oil and gas production.
  - Emissions displaced by co-products of alternative fuels  
Emissions displaced by co-products of various pathways. System expansion is used to determine displacement ratios for co-products from biomass pathways.
  - Vehicle assembly and transport  
Emissions associated with the manufacture and transport of the vehicle to the point of sale, amortized over the life of the vehicle.
  - Materials used in the vehicles  
Emissions from the manufacture of the materials used to manufacture the vehicle, amortized over the life of the vehicle. Includes lube oil production and losses from air conditioning systems.

The main lifecycle stages for crude oil based gasoline or diesel fuel are shown in the following figure.

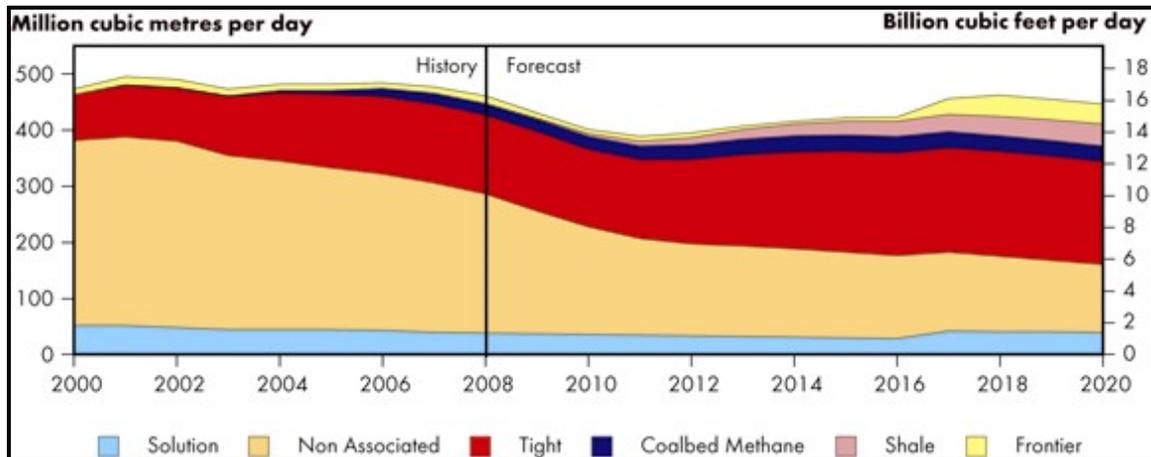
**Figure 1-1 Lifecycle Stages**



### 1.1 SCOPE OF WORK

Canadian production of conventional natural gas is declining and is expected to continue to decline over the next few years. The National Energy Board, in their latest forecast, sees coal bed methane, shale gas, and eventually frontier gas supplementing declining supplies of conventional gas and tight gas as shown in the following figure.

**Figure 1-2 Forecast Natural Gas Supply**



The types of gas shown in the figure can be classified as follows:

- Solution gas is that which is dissolved in crude oil under pressure and is produced at the same time as crude oil is produced.
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The goal of this work was to modify the natural gas pathways in GHGenius to accommodate these different sources of natural gas. The GHGenius user can now choose to model each type of natural gas individually or a blend of the different types of production. The data used for modelling these different sources of gas was not as well developed as the data for conventional gas and the model has been developed so that it is easy to change these inputs as better data become available.

The new version of the model that accompanies this report is version 3.18. The data in the report is from the model using Canada average as the region, the year 2010, and the 2007 IPCC GWPs unless otherwise specified.

## 2. CONVENTIONAL NATURAL GAS

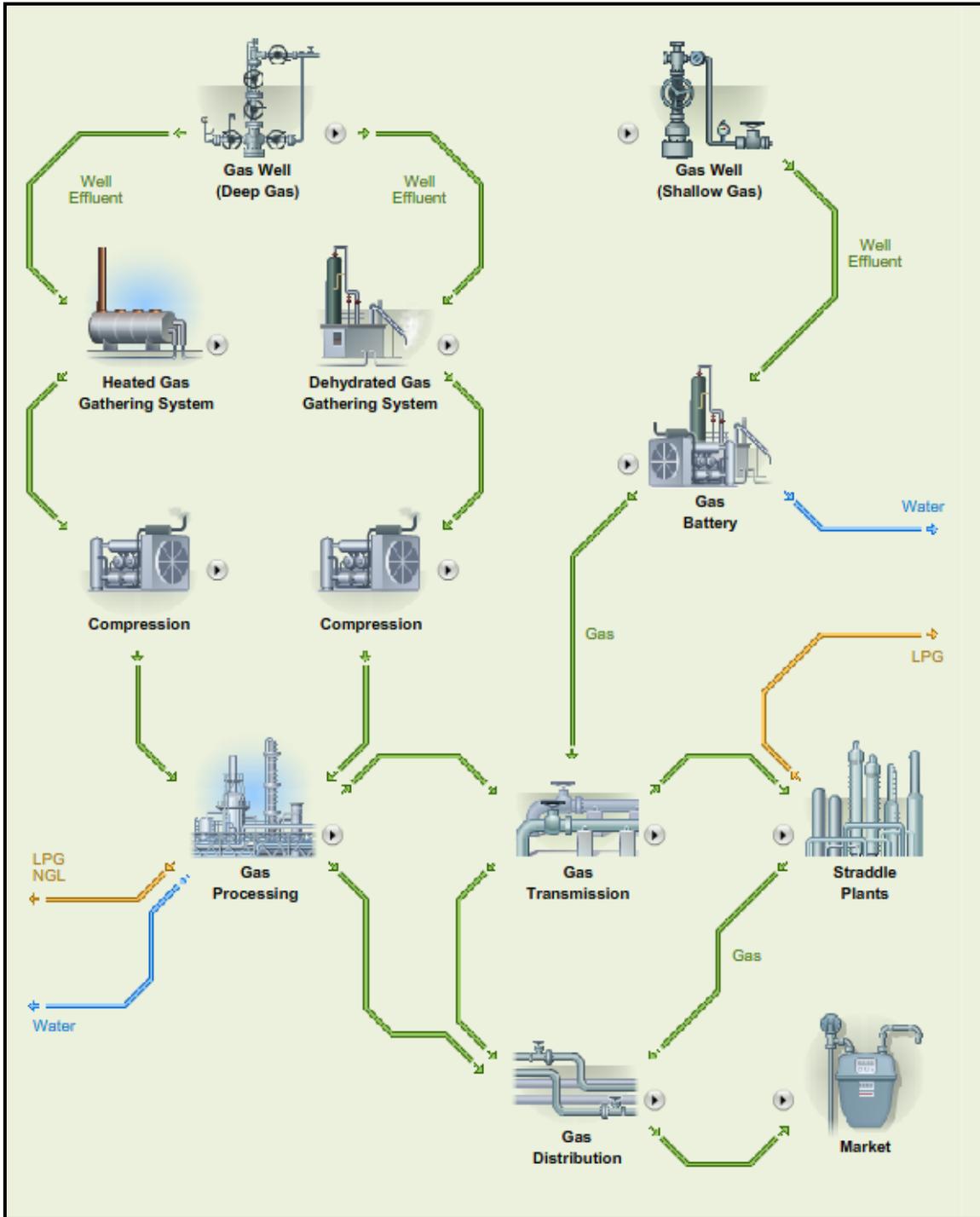
Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, and transmission and distribution pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user, which can generally be broken out into four sectors. Each sector is defined as follows:

- Production focuses on taking raw natural gas from underground formations.
- Processing focuses on stripping out impurities and other hydrocarbons and fluids to produce pipeline grade natural gas that meets specified tariffs (pipeline quality natural gas is 95-98 percent methane).
- Transmission and Storage focuses on delivery of natural gas from the wellhead and processing plant to city gate stations or industrial end users. Transmission occurs through a network of high-pressure pipelines. Natural gas storage also falls within this sector. Natural gas is typically stored in depleted underground reservoirs, aquifers, and salt caverns.
- Distribution focuses on the delivery of natural gas from the major pipelines to the end users (e.g., residential, commercial and industrial).

In the oil industry, some underground crude contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, associated or solution natural gas is produced. Both associated and non-associated gases are considered conventional natural gas as part of this work.

All of these sectors are currently accounted for in GHGenius. The following figure shows the flow of gas from the well to the end market.

**Figure 2-1 Natural Gas Production System**



Source: Methane to Markets. Sponsored by NRCan.

It is apparent from the figure that the emissions from different gas fields could be quite different as the processing of the gas that is required will be a function of the impurities in the gas. Dry shallow wells may receive minimal processing prior to compression, transmission

and distribution, whereas deep wet gas may require significantly more processing to achieve the same composition that is suitable for downstream use. In GHGenius, these different sources of gas have not previously been segregated.

## 2.1 NATURAL GAS PRODUCTION

Natural gas production emissions are those associated with drilling the wells and producing the gas. The main emission sources are from the use of energy to compress the gas and from leaks and flares from equipment. These emissions are found in the feedstock recovery stage and the gas leaks and flares stages in GHGenius.

In many fields, natural gas is also used to drive pneumatic devices, as compressed air is not available. This gas is usually exhausted to the atmosphere as a component of the gas leaks and flares in GHGenius. There is an opportunity to reduce these emissions, through the use of compressed air, particularly in larger fields.

Good quality data on the energy expended in drilling wells is not often reported. CAPP (2004) has reported the emissions for well drilling, well servicing and well testing on a per well basis. This information is summarized in the following table.

**Table 2-1 GHG Emissions – Well Drilling**

|                | Tonnes/well     |                 |                  |                    |
|----------------|-----------------|-----------------|------------------|--------------------|
|                | CO <sub>2</sub> | CH <sub>4</sub> | N <sub>2</sub> O | CO <sub>2</sub> eq |
| Well Drilling  | 61.1            | 0.023           | 0.0055           | 63.3               |
| Well Servicing | 15.0            | 0.51            | 0.0018           | 28.3               |
| Well Testing   | 42.7            | 0.24            | ----             | 48.7               |
| Total          | 118.8           | 0.773           | 119.573          | 140.3              |

The productivity of a gas well ranges from 5.1 to 58 million m<sup>3</sup>/well with a typical value of 50 million m<sup>3</sup>/well (Jordaan, 2009). This would equate to 2.8 g CO<sub>2</sub>eq/m<sup>3</sup> of gas production or about 75 g CO<sub>2</sub>eq/GJ. This value was incorporated in the energy use data for oil and gas production in GHGenius.

Historically data on natural gas production has been aggregated across all types of natural gas production. This work is one of the first to try to segregate the data into different categories of natural gas production. The focus of the work is on differences in energy use for gas production and differences in venting and flaring practices. It is recognized that there could be other differences, such as the energy required to drill the wells and put them into production, but there is very little detail on these emission sources available. These emissions would also need to be amortized over the producing life of the well and so they do tend to be small compared to the emissions associated with actually producing the gas.

Changes have been made to sheet R in the model to accommodate the additional sources of natural gas.

## 2.2 NATURAL GAS PROCESSING

Natural gas, as it is produced, can contain varying levels of impurities that must be removed before it can be moved to market. These impurities can include water, carbon dioxide, higher hydrocarbons, and hydrogen sulphides. The level of impurities will vary from field to field.

The stripping of these compounds from natural gas requires energy and can result in methane losses and the venting of the impurities. The most significant impurity from a GHG

emissions perspective is carbon dioxide. The calculation of these emissions is found on sheet F, cell A44 of the model. These calculations have been modified to accommodate the additional types of natural gas.

The calculations on sheet F have not been country specific. They have been based on US data and the result is that the emissions represent a CO<sub>2</sub> emission rate of 1.46% of the dry gas volume (1.30% of the total gas volume on the Upstream Results sheet). The processed gas entering the pipeline still contains 0.5% CO<sub>2</sub>.

Data from CAPP (2004) would indicate that these emissions in Canada (identified as formation gas) are 29% higher than the total gas value in the model. The structure of the model has been changed to allow for regional factors for this formation gas. This will also facilitate the application of an individual factor for each type of gas produced in Canada.

### **2.3 NATURAL GAS TRANSMISSION**

The natural gas transmission stage involves energy to compress the gas to move it through the main gas transmission network and any methane losses from the system. The emissions associated with the energy use for the compression of the gas are in the fuel transmission and storage stage in GHGenius. The emissions of gas from the system are included in the gas leaks and flares stage of the model. These emissions are independent of the type of gas that is produced and are not impacted by the changes made to the model as part of this work.

### **2.4 NATURAL GAS DISTRIBUTION**

The natural gas distribution system delivers gas from the main transmission lines to the end users. The primary source of GHG emissions is the lost gas from equipment and leaks. In GHGenius, these emissions are shown as part of the gas leaks and flares stage. These emissions are independent of the type of gas that is produced in the field and is not discussed further in this report.

### **2.5 CONVENTIONAL NATURAL GAS EMISSIONS**

The GHG emissions for natural gas delivered to different users are summarized in the following table.

**Table 2-2 GHG Emissions Conventional Natural Gas Production**

| Fuel Use   | NG to power             | NG to industry | NG to commerce |
|--|-------------------------|----------------|----------------|
|  | g CO <sub>2</sub> eq/GJ |                |                |
| Fuel dispensing                                    | 0                       | 0              | 0              |
| Fuel distribution and storage                      | 1,173                   | 1,173          | 1,303          |
| Fuel production                                    | 1,375                   | 1,377          | 1,377          |
| Feedstock transmission                             | 0                       | 0              | 0              |
| Feedstock recovery                                 | 1,709                   | 1,712          | 1,710          |
| Land-use changes, cultivation                      | 0                       | 0              | 0              |
| Fertilizer manufacture                             | 0                       | 0              | 0              |
| Gas leaks and flares                               | 779                     | 1,349          | 1,369          |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 823                     | 824            | 824            |
| Emissions displaced                                | 0                       | 0              | 0              |
| Total  | 5,860                   | 6,435          | 6,584          |

These emissions are slightly higher than in the previous version of GHGenius as a result of including Canada specific values for CO<sub>2</sub> released from the gas (formation gas) during processing.

It can be seen that the primary difference in emissions between the different gas applications is the quantity of gas that is leaked and flared and this is a function of the assumptions that are made about the quantity of gas that is delivered to each user and whether or not it is delivered through the local distribution system. The upstream GHG emissions associated with natural gas production, processing, transmission, and distribution amount to 15 to 20% of the full lifecycle emissions associated with natural gas production and use.

The emissions could also be shown on the basis of grams per cubic metre of gas and this data is presented in the following table.

**Table 2-3 GHG Emissions Conventional Natural Gas Production**

| Fuel Use   | NG to power                      | NG to industry | NG to commerce |
|--|----------------------------------|----------------|----------------|
|  | g CO <sub>2</sub> eq/cubic metre |                |                |
| Fuel dispensing                                    | 0.0                              | 0.0            | 0.0            |
| Fuel distribution and storage                      | 44.4                             | 44.4           | 49.3           |
| Fuel production                                    | 52.1                             | 52.1           | 52.1           |
| Feedstock transmission                             | 0.0                              | 0.0            | 0.0            |
| Feedstock recovery                                 | 64.7                             | 64.8           | 64.8           |
| Land-use changes, cultivation                      | 0.0                              | 0.0            | 0.0            |
| Fertilizer manufacture                             | 0.0                              | 0.0            | 0.0            |
| Gas leaks and flares                               | 29.5                             | 51.1           | 51.8           |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 31.2                             | 31.2           | 31.2           |
| Emissions displaced                                | 0.0                              | 0.0            | 0.0            |
| Total  | 221.8                            | 243.6          | 249.2          |

The gas leaks and flares emissions are broken out in the following table for each of the four stages in the production process.

**Table 2-4 Gas Leaks and Flares Emissions**

| Fuel Use         | NG to power                      | NG to industry | NG to commerce |
|------------------|----------------------------------|----------------|----------------|
|                  | g CO <sub>2</sub> eq/cubic metre |                |                |
| Gas production   | 15.9                             | 15.9           | 15.9           |
| Gas processing   | 6.9                              | 6.9            | 6.9            |
| Gas transmission | 6.7                              | 6.7            | 7.4            |
| Gas distribution | 0.0                              | 21.6           | 21.6           |
| Total            | 29.5                             | 51.1           | 51.8           |

### 3. COALBED METHANE

Coalbed methane (CBM) is natural gas found in coal. CBM is composed mostly of methane (CH<sub>4</sub>) but may have minor amounts of nitrogen, carbon dioxide and heavier hydrocarbons like ethane. It forms naturally as a by-product of the geological process that turns plant materials to coal.

CBM is considered an unconventional form of natural gas because the coal acts both as the source of the gas and the storage reservoir. As well, the gas is primarily adsorbed on the molecular surface of the coal rather than stored in pore spaces, as occurs in conventional gas reservoirs.

The gas adsorbed within coals is held there mostly by pressure. If the pressure is reduced, the gas is released from the coal and free to flow to a well. The amount of gas liberated from a given coal seam is a function of many factors, including the chemical composition of the coal, the geological history of the coal, and whether the coal had been previously depressured.

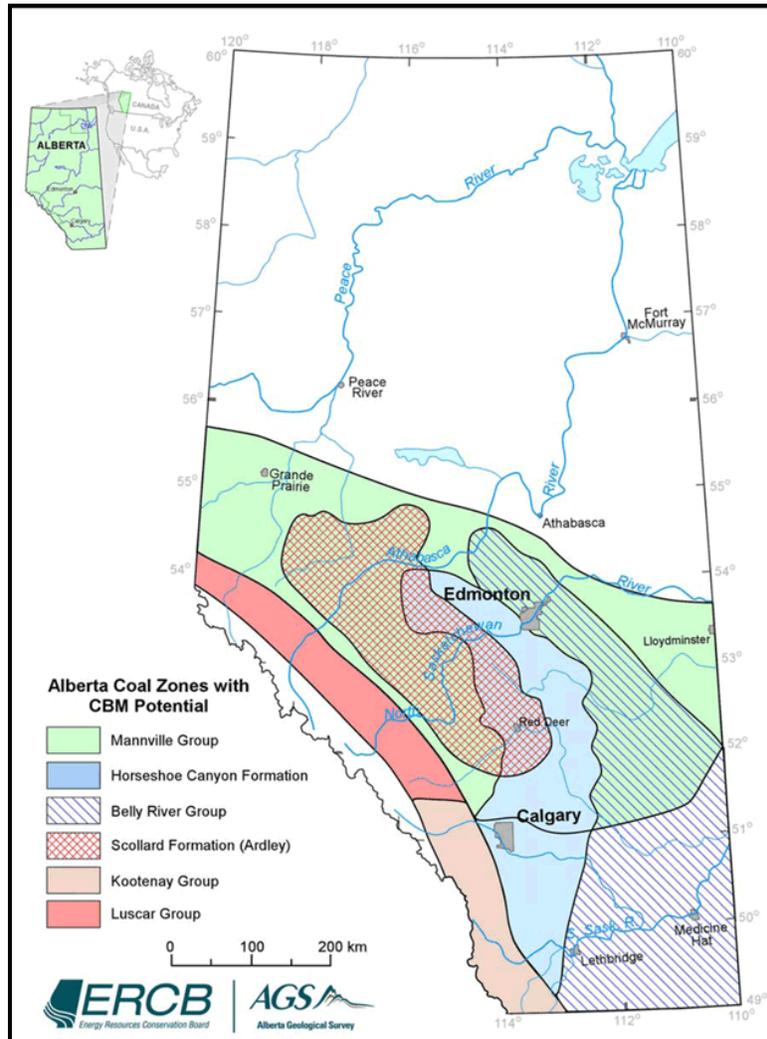
#### 3.1 RESOURCE DESCRIPTION

Coalbed methane can be found in significant quantities in Alberta and British Columbia and in smaller quantities in the Maritimes.

Coal seams with CBM potential are found underneath much of Alberta, especially in southern and central Alberta as shown in the following figure. The Alberta Geological Survey recently estimated there could be as much as 14 trillion cubic metres of coalbed methane held in Alberta coal. For comparison, a joint study by the Alberta Energy and Utilities Board (ERCB) and the National Energy Board in 2006 estimated the ultimate potential of marketable conventional natural gas in Alberta to be between 5.7 and 7.1 trillion cubic metres with 2.8 trillion cubic metres being the estimate of remaining ultimate potential after consideration of past gas production.

The Alberta resources are shown in the following figure.

**Figure 3-1 Alberta Coalbed Methane Resources**

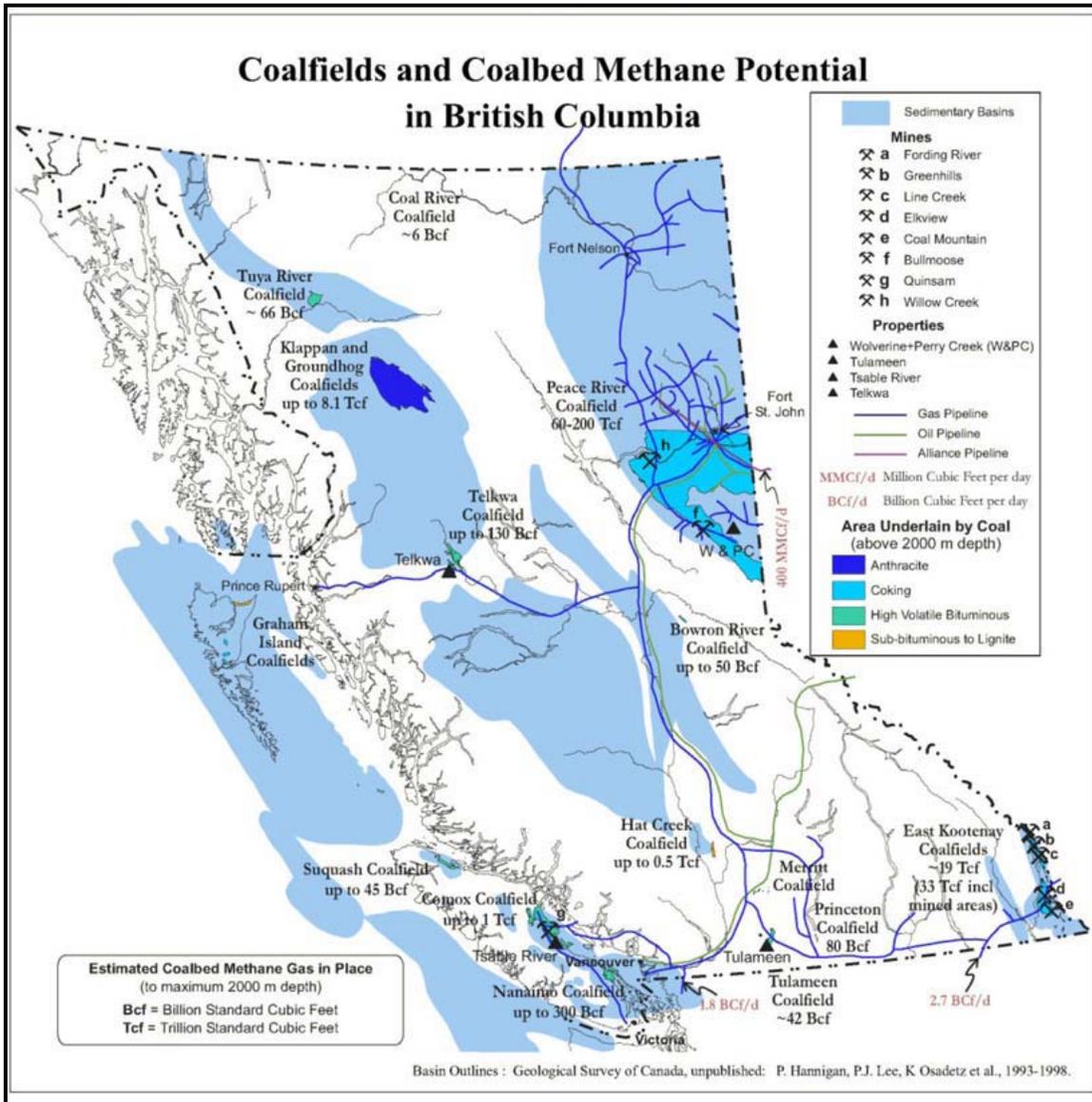


Production of CBM in Alberta was 2.9 billion cubic metres in 2005 and is forecast to increase to 19.6 billion cubic metres in 2015. This would represent an increase from less than 2 per cent in 2005 to about 16 per cent in 2015 of total Alberta marketable gas production.

As of December 31, 2006, 10,723 CBM wells were drilled in Alberta, with approximately 2,000 CBM wells drilled in 2005. The total number of producing conventional gas wells in Alberta in 2005 was 97,900, with 13,248 conventional gas wells drilled in 2005, slightly less than 12,000 of these were connected and producing.

British Columbia has an estimated resource of 3 trillion cubic metres of coalbed gas. This potential is located throughout the province as shown in the following figure.

Figure 3-2 BC Coalbed Methane Resources



### 3.2 ENERGY REQUIREMENTS

The production of coal bed methane follows a similar approach to the production of conventional natural gas. There are wells drilled, these are similar to the wells for conventional gas; the wells must be completed, which will include perforating and fracturing; the wells are tested, which includes flaring the gas; the wells must be connected to a pipeline; and finally put into service where there may be compressors and pumps used to move the gas and deal with any produced water.

Given the relative early stage of development of this resource there does not appear to be very much data available on the energy requirements of the various stages of developing and producing coalbed methane.

The Pembina Institute (2003) identified some of the environmental issues associated with coalbed methane production in Alberta. These are summarized in the following table.

**Table 3-1 Coalbed Methane Production Environmental Issues**

| Issue                          | Description   | Potential impact   |
|--------------------------------|---|--|
| High density of wells          | An average of two to eight wells per section to access the gas compared to the basic standard of one well per section for conventional natural gas.   | Land use is not currently included in GHGenius for conventional petroleum production but this could increase GHG emissions from land use. It also suggests more energy expended for well drilling if the production intensity of each well is lower. |
| Dewatering of coal             | While some coal seams are dry, many will require significant amounts of dewatering to relieve pressure before gas can be extracted. Conventional gas wells generally produce no water at the start of development, although water may be pumped from a well as it ages. | Water will have to be pumped back into wells and thus more energy will be expended because of this leading to higher GHG emissions.  |
| Venting and flaring of CBM gas | During dewatering, CBM may be vented or flared until gas volumes are economic to pipeline. The duration will likely be for much longer periods than that experienced with conventional gas wells.   | GHG emissions will be higher due to incomplete combustion.   |
| Noise                          | Where coal seams need dewatering, the lower gas pressure and higher density of CBM wells compared to conventional gas wells will result in increased intensity of pumps and compressors used to dewater the coal seams and pressurize the gas.                          | Higher energy consumption will result from the additional operating equipment.   |

Offsetting some of these directional issues with coalbed methane is the fact that the resources are often found closer to the surface and thus the total drilling requirements may be the same or lower than conventional gas. Also not all coalbed methane is “wet” and the energy requirements of “dry” coalbed methane will be lower since the produced water does not have to be managed.

One estimate of the energy intensity of coalbed methane has been identified (Clearstone Engineering, 2009). This information is shown in the following table.

**Table 3-2 Emission Intensity – Natural Gas Production**

|                  | 2006                                | 2020 | 2050 |
|------------------|-------------------------------------|------|------|
|                  | g CO <sub>2</sub> eq/m <sup>3</sup> |      |      |
| Conventional Gas | 130                                 | 120  | 85   |
| Coalbed Methane  | 84                                  | 84   | 84   |

While the data is from the same report, there appears to be a difference in the emissions that are included in each estimate. The conventional gas emissions appear to include all sources of emissions whereas the coalbed methane estimates may not. The detail for each is summarized in the following table.

**Table 3-3 Detail Emission Intensity – Natural Gas Production**

|                          | 2006                                | 2020 | 2050 |
|--------------------------|-------------------------------------|------|------|
|                          | g CO <sub>2</sub> eq/m <sup>3</sup> |      |      |
| <b>Conventional gas</b>  |                                     |      |      |
| Fuel combustion          | 72                                  | 62   | 33   |
| Dehydrator off-gas       | 5                                   | 5    | 4    |
| Flaring                  | 1                                   | 3    | 4    |
| Fugitive equipment leaks | 30                                  | 32   | 35   |
| Reported venting         | 1                                   | 1    | 0    |
| Storage losses           | 1                                   | 1    | 0    |
| Unreported venting       | 20                                  | 17   | 8    |
| Total                    | 130                                 | 120  | 85   |
| <b>Coalbed methane</b>   |                                     |      |      |
| Compressor station       | 53                                  | 53   | 53   |
| Gas battery              | 31                                  | 31   | 31   |
| Total                    | 84                                  | 84   | 84   |

In order to compare the emissions from conventional gas production to those in GHGenius it is necessary to ensure that the system boundaries are comparable. The GHGenius results prior to transmissions and distribution are 170 g CO<sub>2</sub>eq/m<sup>3</sup> compared to the 130 value in this table, but it is not clear that CO<sub>2</sub> venting is included in the above estimate nor are the emissions or well drilling, servicing, or testing.

The average production of coalbed methane wells in Alberta in 2008 was 2,100 m<sup>3</sup>/day. The life of a CBM well has been estimated at up to 40 years but the rate of production will decline over time. It is likely that each well could produce 15 million m<sup>3</sup> of gas in its lifetime. This is about one third of the rate of a conventional gas well in Alberta, which is consistent with the more dense well spacing for CBM fields. The GHG emissions associated with well drilling is therefore about 9 g CO<sub>2</sub>eq/m<sup>3</sup> and that the total emissions for CBM production are about 93 g CO<sub>2</sub>eq/m<sup>3</sup>. These emissions are still less than a conventional oil well.

### 3.3 COMPOSITION

The composition of coalbed methane can vary from field to field but does appear to be very high in methane content and low in carbon dioxide and hydrogen sulphide. One analysis from Encana was identified (Reason, 2007) and that is shown in the following table along with the composition for conventional raw gas. Coalbed methane gas composition has

always been included in GHGenius and it is shown in the following table. No changes are required for this work.

**Table 3-4 Coalbed Methane Composition**

|                                 | Raw NG   | Coalbed Methane |          |
|---------------------------------|----------|-----------------|----------|
|                                 | GHGenius | Encana          | GHGenius |
| Volume Fraction                 |          |                 |          |
| CH <sub>4</sub>                 | 0.87     | 0.9719          | 0.96     |
| C <sub>2</sub> H <sub>6</sub>   | 0.04     | 0.0035          | 0.00     |
| C <sub>3</sub> H <sub>8</sub>   | 0.02     | 0.0004          | 0.00     |
| C <sub>4</sub> H <sub>10</sub>  | 0.01     | 0.0001          | 0.00     |
| C <sub>5</sub> H <sub>12+</sub> | 0.01     | 0               | 0.00     |
| CO <sub>2</sub>                 | 0.02     | 0.0011          | 0.01     |
| CO                              | 0.00     | 0               | 0.00     |
| N <sub>2</sub>                  | 0.02     | 0.0220          | 0.02     |
| H <sub>2</sub>                  | 0.00     | 0.0009          | 0.00     |
| H <sub>2</sub> S                | 0.01     | 0               | 0.00     |
| H <sub>2</sub> O                | 0.00     | 0               | 0.00     |
|                                 | 1.00     | 0.9999          | 1.00     |
| Density, g/litre                | 0.81     |                 | 0.70     |

### 3.4 FLARING AND VENTING

Limited information is available on the venting and flaring associated with natural gas from coalbed methane. Some information on the total quantities produced, vented and flared is included in Alberta's Energy Reserves 2007 and 2008 and Supply/Demand Outlooks (ERCB, 2008, 2009) and in the Upstream Petroleum Industry Flaring and Venting Report, 2008 (ERCB 2009b). This information is summarized in the following table.

**Table 3-5 Coalbed Methane Venting and Flaring**

|  | 2007 | 2008 | Avg  |
|--|------|------|------|
| Production, 10 <sup>9</sup> m <sup>3</sup>   | 6.0  | 8.0  | 7.0  |
| Venting, 10 <sup>6</sup> m <sup>3</sup>      | 3.0  | 0.0  | 1.5  |
| Venting, m <sup>3</sup> /1000 m <sup>3</sup> | 0.5  | 0.0  | 0.21 |
| Flaring, 10 <sup>6</sup> m <sup>3</sup>      | 20   | 6    | 13   |
| Flaring, m <sup>3</sup> /1000 m <sup>3</sup> | 3.3  | 0.75 | 1.86 |

There is significant variation in the data for the two years for which information is available. The GHG emissions can be calculated from this data and those results are summarized in the following table.

**Table 3-6 Coalbed Methane GHG Emission Intensity**

|  | 2007 | 2008 | Avg  |
|--|------|------|------|
| Venting, m <sup>3</sup> /1000 m <sup>3</sup>     | 0.5  | 0.0  | 0.21 |
| Venting GHG, g CO <sub>2</sub> eq/m <sup>3</sup> | 25   | 0    | 11   |
| Flaring, m <sup>3</sup> /1000 m <sup>3</sup>     | 3.3  | 0.75 | 1.86 |
| Flaring GHG, g CO <sub>2</sub> eq/m <sup>3</sup> | 10.8 | 2.5  | 6.1  |

These emissions would appear to be less than the 22.8 g CO<sub>2</sub>eq/m<sup>3</sup> for conventional gas production that is currently in GHGenius.

### 3.5 SUMMARY

There is very little hard data available for the energy used to produce coalbed methane and emissions resulting from the production of the gas. The data that is available would suggest the overall GHG emissions are lower than they are for conventional natural gas, primarily due to the lack of gas processing required. This information is summarized in the following table. While the processing factor is shown as zero in the table, in the model it is set to be a very small non-zero value to prevent a divide by zero error propagating through the model.

**Table 3-7 Comparison of Conventional Gas and CBM**

|                          | Conventional Gas                 | CBM | Adjustment Factors |
|--------------------------|----------------------------------|-----|--------------------|
|                          | g CO <sub>2</sub> eq/cubic metre |     |                    |
| Drilling                 | Inc.                             | 9   |                    |
| Recovery                 | 64.7                             | 84  | 1.43               |
| Processing               | 52.1                             | 0   | 0.0                |
| Venting and Flaring      | 22.8                             | 17  | 0.75               |
| CO <sub>2</sub> releases | 31.2                             | 0   | 0.0                |
|                          | 170.8                            | 110 |                    |

The comparison of emissions with conventional gas is shown in the following table. The GHG emissions for CBM would appear to be lower than they are for conventional gas because of the lack of processing required to remove any gas liquids and ethane.

**Table 3-8 CBM and Conventional Gas GHG Emissions**

| Fuel   | Conventional Gas        | Coalbed Methane |
|--|-------------------------|-----------------|
| Use  | commerce                |                 |
|  | g CO <sub>2</sub> eq/GJ |                 |
| Fuel dispensing                                    | 0                       | 0               |
| Fuel distribution and storage                      | 1,303                   | 1,249           |
| Fuel production                                    | 1,377                   | 0               |
| Feedstock transmission                             | 0                       | 0               |
| Feedstock recovery                                 | 1,710                   | 1,663           |
| Land-use changes, cultivation                      | 0                       | 0               |
| Fertilizer manufacture                             | 0                       | 0               |
| Gas leaks and flares                               | 1,369                   | 1,029           |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 824                     | 0               |
| Emissions displaced                                | 0                       | 0               |
| Total  | 6,584                   | 3,941           |

This data would suggest that some of the concerns raised by Pembina may not be valid, or alternatively more information on the actual performance of these systems is required.

## 4. SHALE GAS

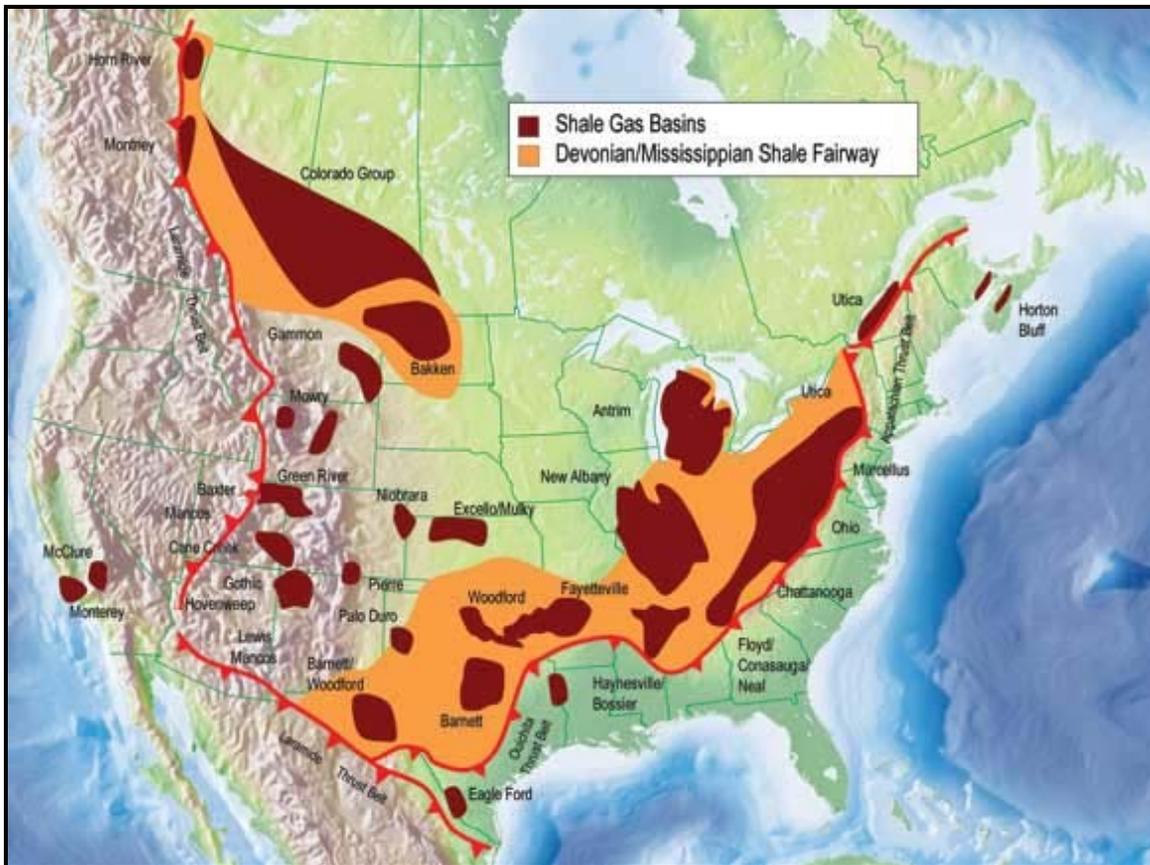
Shale gas is natural gas that is embedded in shale, a sedimentary rock that was originally deposited as clay and silt. Similar in appearance to a chalkboard slate, shale is the most common sedimentary rock on Earth. Shales are less permeable than concrete, so the natural gas cannot easily move through the rock and into a well. New technologies, such as multistage hydraulic fracturing or “fracking” in industry terms, combined with horizontal drilling, are making it easier and cheaper to produce shale gas.

### 4.1 RESOURCE DESCRIPTION

Despite being difficult to drill, there are potentially 30 trillion cubic metres of shale gas in Canada. Normally, only 20 per cent of the gas can be recovered, but the industry believes that this could grow with advancements in drilling and fracturing technology.

In North America, there are several shale gas opportunities, shown in the map below. While the potential for Canadian shale gas production is still being evaluated, the principal Canadian shale gas plays are the Horn River Basin and Montney shales in northeast British Columbia, the Colorado Group in Alberta and Saskatchewan, the Utica Shale in Quebec and the Horton Bluff Shale in New Brunswick and Nova Scotia.

**Figure 4-1 North American Shale Gas Resources**



Information on the Canadian shale gas resources that are currently being evaluated are summarized below (National Energy Board):

- Montney Formation – The production of natural gas from horizontal shale gas wells in the Montney of northeast B.C. has risen from zero in 2005 to 10.7 million cubic metres per day and is expected to continue rising. As of July 2009, 234 horizontal wells were producing from the Montney shale. The National Energy Board classifies the Montney formation as tight gas in its production forecasts.
- Horn River Basin - Wells in this basin in northeast British Columbia are prolific and produce an average initial flow rate of 230,000 cubic metres per day.
- Colorado Group - The Colorado Group of southern Alberta and Saskatchewan have been producing natural gas from shale for over 100 years.
- Utica Group - These shales, located between Montreal and Quebec City near the Appalachian Mountain front, have an increased potential for natural fractures. The potential for shale gas from the Utica Group is still in the early evaluation stages.
- Horton Bluff Group - While still in the early evaluation stage, two vertical wells drilled in New Brunswick have flowed 4,200 cubic metres per day after undergoing small fractures.

**Table 4-1 Comparison of Canadian Gas Shales**

|  | Horn River     | Montney        | Colorado  | Utica           | Horton Bluff    |
|--|----------------|----------------|-----------|-----------------|-----------------|
| Depth (m)  | 2,500 to 3,000 | 1,700 to 4,000 | 300       | 500 to 3,300    | 1,120 to 2,000+ |
| Thickness (m)  | 150            | Up to 300      | 17 to 350 | 90 to 300       | 150+            |
| Published estimate of natural gas (Tm <sup>3</sup> )               | 4 to 14+       | 2 to 20+       | > 3       | > 4             | > 4             |
| Well Cost, including infrastructure. \$ million. Horizontal wells. | 7 to 10        | 5 to 8         | 0.35      | (vertical only) | 5 to 9          |
| CO <sub>2</sub> Levels, %  | 12             | 1              | -         | < 1             | 5               |

## 4.2 ENERGY REQUIREMENTS

Information on the energy requirements for producing gas from shale deposits has not been identified. The drilling process is much more expensive than a traditional oil or gas well and much more energy must be applied to fracture the shale so that the gas can be produced. At the same time, fewer wells are drilled through the use of horizontal drilling technology and there is a higher productivity for each well.

It will be assumed that the energy requirements and GHG emissions associated with that energy for the production stage are the same for shale gas as they are for conventional gas. The structure of the model has been set up so that this can be easily changed in the future if information becomes available.

## 4.3 COMPOSITION

This is the one area where there is some specific information available on shale gas. Each field is quite different with different CO<sub>2</sub> levels and different quantities of natural gas liquids. Currently only the Montney shale has any significant production and that field is low in CO<sub>2</sub> and gas liquids. Some limited production is happening from the Horn River field and this field

has significant quantities of CO<sub>2</sub> in the gas. The must be stripped from the gas before it enters the pipeline system and this gas is either then released into the atmosphere or it can be sequestered in the ground in some cases.

Due to the CO<sub>2</sub> content the model has been set up to reflect the varying CO<sub>2</sub> content of each field and this is combined with gas production data to arrive at the estimated average CO<sub>2</sub> content for shale gas.

#### 4.4 FLARING AND VENTING

No information was identified on methane leaks and flares for shale gas. For the present time, it has been assumed that these rates are the same as for conventional gas production.

#### 4.5 SUMMARY

The relative factors used for shale gas in the model are summarized in the following table.

**Table 4-2 Relative Emission Factors for Shale Gas**

| Parameter     | Stage           | Factor |
|---------------|-----------------|--------|
| Energy        | Recovery        | 1.00   |
|               | Processing      | 1.00   |
|               | Pipeline        | 1.00   |
| Venting       | Recovery        | 1.00   |
|               | Processing      | 1.00   |
|               | Transmission    | 1.00   |
| Formation Gas | CO <sub>2</sub> | 3.87   |

The GHG emissions for shale gas are summarized in the following table and compared to conventional gas and CBM. The emissions are higher due to the higher CO<sub>2</sub> content of some of the gas reservoirs.

**Table 4-3 Shale Gas Emissions and Comparison**

| Fuel   | Conventional Gas        | Coalbed Methane | Shale gas |
|--|-------------------------|-----------------|-----------|
| Use  | commerce                |                 |           |
|  | g CO <sub>2</sub> eq/GJ |                 |           |
| Fuel dispensing                                    | 0                       | 0               | 0         |
| Fuel distribution and storage                      | 1,303                   | 1,249           | 1,340     |
| Fuel production                                    | 1,377                   | 0               | 1,414     |
| Feedstock transmission                             | 0                       | 0               | 0         |
| Feedstock recovery                                 | 1,710                   | 1,663           | 1,742     |
| Land-use changes, cultivation                      | 0                       | 0               | 0         |
| Fertilizer manufacture                             | 0                       | 0               | 0         |
| Gas leaks and flares                               | 1,369                   | 1,029           | 1,369     |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 824                     | 0               | 2,473     |
| Emissions displaced                                | 0                       | 0               | 0         |
| Total  | 6,584                   | 3,941           | 8,338     |

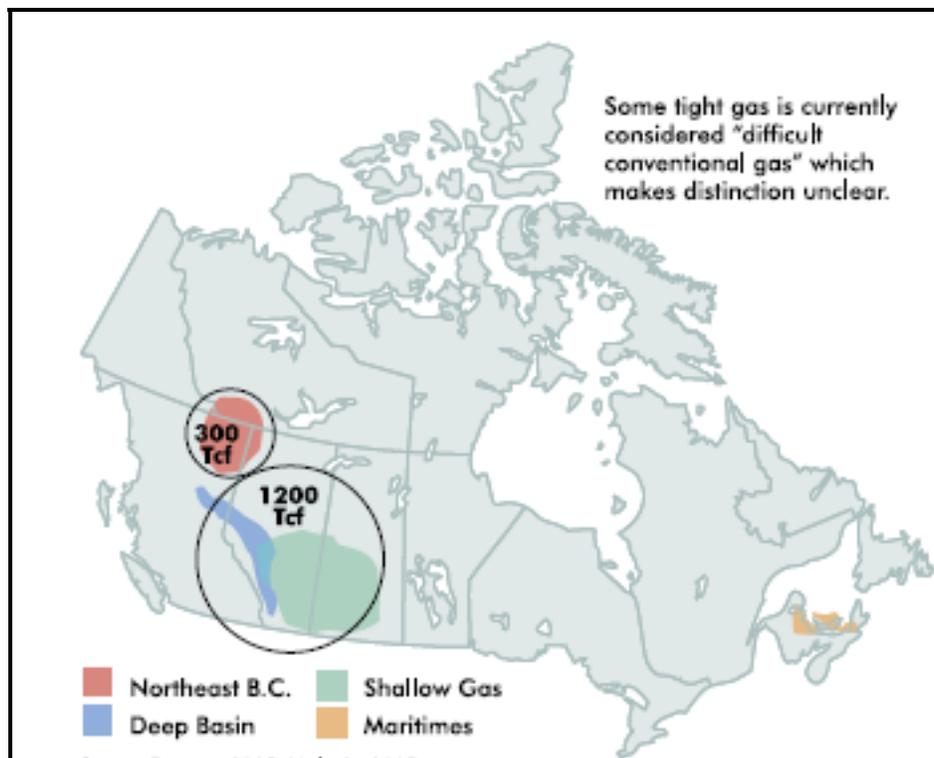
## 5. TIGHT GAS

Tight gas refers to natural gas in underground reservoirs with low permeability. A generally accepted industry definition is reservoirs that do not produce economic volumes of natural gas without assistance from massive stimulation treatments or special recovery processes and technologies, such as horizontal wells. Low permeability is primarily due to the fine-grained nature of the sediments, compaction, or infilling of pore spaces by carbonate or silicate cements.

### 5.1 RESOURCE DESCRIPTION

The definition of tight gas can vary and as discussed in the previous section some fields can be classified as both tight gas and shale gas (Montney). The tight gas fields are shown in the following figure (PTAC).

**Figure 5-1 TIGHT GAS – Development Areas and Estimated Gas in Place**



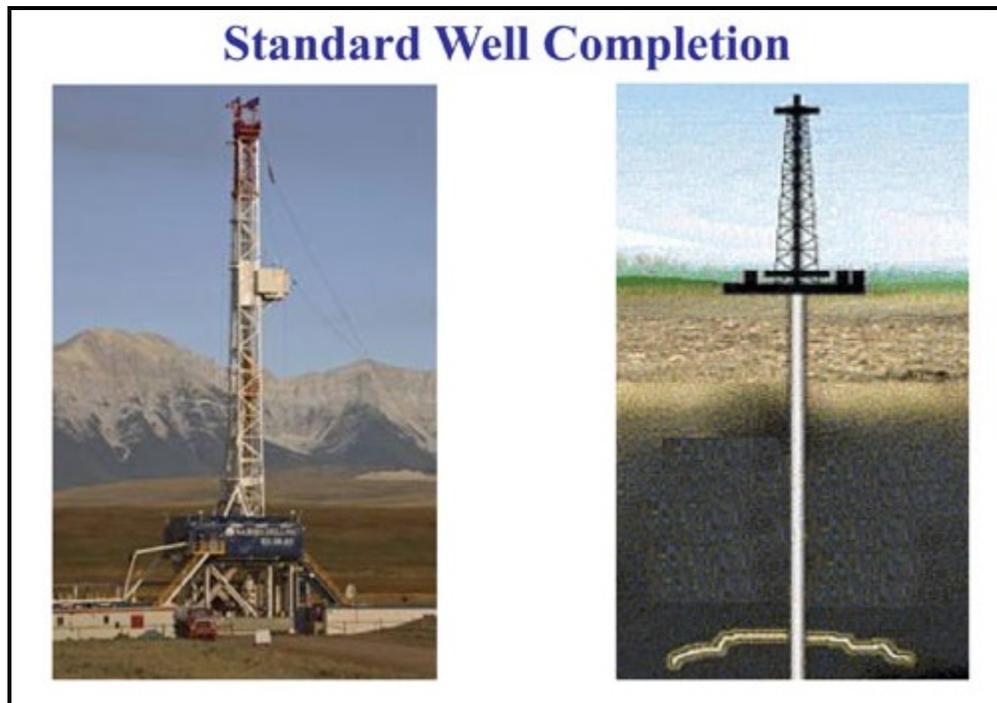
### 5.2 ENERGY REQUIREMENTS

Historically, it has not been the practice in Canada to distinguish between conventional and unconventional gas production from sandstones and limestones. Only in the last decade or so, has tight zone production been increasingly recognized and targeted for development. Significant tight gas production occurs in shallow gas plays in Saskatchewan and Alberta, the deep basin of Alberta and British Columbia, as well as a new development in New Brunswick.

Advances in drilling and fracturing technology, higher gas prices, fiscal incentives and changes in regulations have all led to increased tight gas development in Canada.

No specific information on the energy requirements of tight gas production has been identified. It is clear that increased fracturing is required for economic production of gas from tight sands. This will require increased energy input into the well drilling process but it is at least partially offset by higher production rates from these wells. This is apparent from the following pictures of a conventional well and an unconventional well.

**Figure 5-2 Comparison of Well Infrastructures**



### 5.3 COMPOSITION

Based on the limited amount of information available the gas composition of tight gas does not appear to be significantly different from conventional gas.

### 5.4 FLARING AND VENTING

No information was identified on methane leaks and flares for tight gas. For the present time, it has been assumed that these rates are the same as for conventional gas production.

### 5.5 SUMMARY

The relative factors used for tight gas in the model are summarized in the following table.

**Table 5-1 Relative Emission Factors for Tight Gas**

| Parameter     | Stage           | Factor |
|---------------|-----------------|--------|
| Energy        | Recovery        | 1.00   |
|               | Processing      | 1.00   |
|               | Pipeline        | 1.00   |
| Venting       | Recovery        | 1.00   |
|               | Processing      | 1.00   |
|               | Transmission    | 1.00   |
| Formation Gas | CO <sub>2</sub> | 1.29   |

The GHG emissions for shale gas are summarized in the following table and compared to the other gas types. The emissions are the same as for conventional gas due to the lack of available data.

**Table 5-2 Tight Gas Emissions and Comparison**

| Fuel   | Conventional Gas        | Coalbed Methane | Shale gas | Tight Gas |
|--|-------------------------|-----------------|-----------|-----------|
| Use  | commerce                |                 |           |           |
|  | g CO <sub>2</sub> eq/GJ |                 |           |           |
| Fuel dispensing                                    | 0                       | 0               | 0         | 0         |
| Fuel distribution and storage                      | 1,303                   | 1,249           | 1,340     | 1,303     |
| Fuel production                                    | 1,377                   | 0               | 1,414     | 1,377     |
| Feedstock transmission                             | 0                       | 0               | 0         | 0         |
| Feedstock recovery                                 | 1,710                   | 1,663           | 1,742     | 1,710     |
| Land-use changes, cultivation                      | 0                       | 0               | 0         | 0         |
| Fertilizer manufacture                             | 0                       | 0               | 0         | 0         |
| Gas leaks and flares                               | 1,369                   | 1,029           | 1,369     | 1,369     |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 824                     | 0               | 2,473     | 824       |
| Emissions displaced                                | 0                       | 0               | 0         | 0         |
| Total  | 6,584                   | 3,941           | 8,338     | 6,584     |

## 6. FRONTIER GAS

Frontier gas in the NEB reports is defined as gas from Northern Canada or the east coast of Canada. For the purpose of this work, it will be assumed to gas from Northern Canada, as the NEB appears to forecast Mackenzie Valley gas separately from east coast gas.

### 6.1 RESOURCE DESCRIPTION

The Mackenzie Gas Project proposes to develop natural gas fields in the Mackenzie Delta of the Northwest Territories and deliver the natural gas to markets through a pipeline system built along the Mackenzie Valley. The location of the field and the pipeline route is shown in the following figure.

**Figure 6-1 Mackenzie Gas Project**



The Project consists of five major parts:

- three natural gas field production facilities
- a gathering pipeline system
- a gas processing facility near Inuvik
- a natural gas liquids pipeline from the Inuvik area facility to Norman Wells
- a natural gas pipeline from the Inuvik area facility to north western Alberta

The three fields, Niglintgak, Taglu and Parsons Lake, together can supply about 23 million cubic metres per day of natural gas over the life of the Project. Other natural gas fields in the North can be connected into the gathering system or into the main pipeline. In total, as much as 34 million cubic metres per day of natural gas could be available initially to move through the Mackenzie Valley natural gas pipeline.

Each of the Niglintgak, Taglu and Parsons Lake natural gas fields will be connected to a gathering system. This is a network of pipelines that will move the natural gas and natural gas liquids to a gas processing facility near Inuvik.

Natural gas liquids will be separated from the natural gas at the Inuvik area facility and pumped to Norman Wells through a natural gas liquids pipeline. The natural gas will be

compressed and transported to northwestern Alberta in a natural gas pipeline. Gas processing, gas chilling and compression, and liquids stabilization will occur at the Inuvik area facility.

## 6.2 ENERGY REQUIREMENTS

Information on the energy requirements for gas production has not been identified but the report published by the Joint Review Panel (JRP, 2009) for the project does have information on the GHG emissions from various phases of the project that can be used to back calculate the required relative energy consumption factors.

The GHG emissions reported for the production and processing were 3,341 g/GJ and the transportation emissions to move the gas to Edmonton were 1,934 g/GJ.

In GHGenius, the conventional gas emissions for gas recovery and processing are about 3,800 g/GJ. This includes the energy related and the fugitive emissions. The JRP report appears to use older GWPs with only 21 for methane rather than the more recent value of 25 used in the GHGenius value. Relative energy and emission values of 1.0 for recovery and processing would therefore appear to be appropriate for this resource.

The transportation emissions are higher than the value in GHGenius (1,219 g/GJ) and are also additive to the energy and emissions associated with moving conventional gas. A relative energy requirement of 2.6 will be used for this gas source.

## 6.3 COMPOSITION

The gas composition is reported to be sweet gas but the proponents of the projected have noted that the CO<sub>2</sub> content of the individual fields varies considerably and the blending of the gas streams is required to produce pipeline quality gas. The relative CO<sub>2</sub> emission factor for this gas source will therefore be assumed to be 0.0 as no CO<sub>2</sub> will be released from the processing plant.

## 6.4 FLARING AND VENTING

The fugitive emissions are included as part of the GHG emission estimates referenced above. A relative value of 1.0 will be used for modelling.

## 6.5 SUMMARY

**Table 6-1 Relative Emission Factors for Frontier Gas**

| Parameter     | Stage           | Factor |
|---------------|-----------------|--------|
| Energy        | Recovery        | 1.00   |
|               | Processing      | 1.00   |
|               | Pipeline        | 2.60   |
| Venting       | Recovery        | 1.00   |
|               | Processing      | 1.00   |
|               | Transmission    | 1.00   |
| Formation Gas | CO <sub>2</sub> | 0.00   |

The GHG emissions for frontier gas are summarized in the following table and compared to the other gas types. The emissions are higher than conventional gas due to the extra transportation involved and partially offset by the lack of formation gas vented.

**Table 6-2 Frontier Gas Emissions and Comparison**

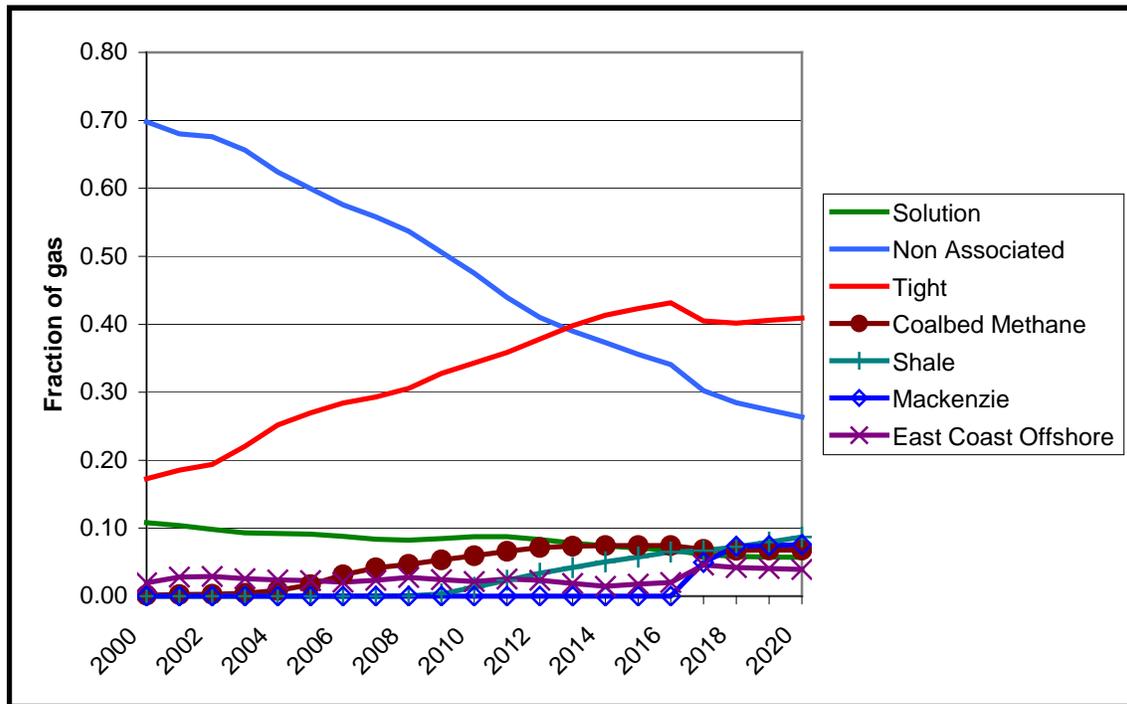
| Fuel   | Conventional Gas        | Coalbed Methane | Shale Gas | Tight Gas | Frontier Gas |
|--|-------------------------|-----------------|-----------|-----------|--------------|
| Use  | commerce                |                 |           |           |              |
|  | g CO <sub>2</sub> eq/GJ |                 |           |           |              |
| Fuel dispensing                                    | 0                       | 0               | 0         | 0         | 0            |
| Fuel distribution and storage                      | 1,303                   | 1,249           | 1,340     | 1,303     | 3,465        |
| Fuel production                                    | 1,377                   | 0               | 1,414     | 1,377     | 1,360        |
| Feedstock transmission                             | 0                       | 0               | 0         | 0         | 0            |
| Feedstock recovery                                 | 1,710                   | 1,663           | 1,742     | 1,710     | 1,697        |
| Land-use changes, cultivation                      | 0                       | 0               | 0         | 0         | 0            |
| Fertilizer manufacture                             | 0                       | 0               | 0         | 0         | 0            |
| Gas leaks and flares                               | 1,369                   | 1,029           | 1,369     | 1,369     | 1,373        |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 824                     | 0               | 2,473     | 824       | 0            |
| Emissions displaced                                | 0                       | 0               | 0         | 0         | 0            |
| Total  | 6,584                   | 3,941           | 8,338     | 6,584     | 7,895        |

## 7. GAS PRODUCTION FORECASTS

GHGenius has treated natural gas a single commodity in all past models. This work has looked at a number of different sources of natural gas and, despite the limited amount of data, has found some differences in the energy requirements and emissions profile from each source.

If this additional detail for different types of natural gas is to be utilized then the proportions of the gas from each source must be known. In the National Energy Board report, Canadian Energy Demand and Supply to 2020, (2009) this information was provided for the period 2000 to 2020. The following figure shows the information on a normalized basis, it is apparent from the figure that gas supply in Canada is changing with the supply of non-associated gas declining significantly. Most of the decline is offset by increasing supplies of tight gas but other sources do start to become important towards the later part of this decade.

**Figure 7-1 Gas Production Forecasts**



There are two issues with the data, the forecast is for a relatively short period of time, which is less than the GHGenius model capability, and gas production from East Coast offshore production is included.

The data available from the NEB starts in the year 2000 and extends to 2020. GHGenius requires data starting in 1995 and extending to 2050. To overcome these limitations estimates for the years 1995 to 1999 have been made.

The period post 2020 is more difficult to project since while it is apparent that the trend to less non-associated gas is probably going to continue, it is not apparent which of the other supply sources will fill the supply gap. It has therefore been assumed that the period post

2020 will have the same proportion of gas supply as the year 2020. When the NEB updates the forecast in the future, this assumption can be revisited.

The gas production from the East Coast offshore is assumed to have the same production characteristics as the non-associated conventional gas since no information on this source was identified.

The user can also override the NEB data and model a single type of gas or a different blend. This is done by selecting "Input" on the drop down menu on sheet R, cell AD 164.

## 8. DISCUSSION AND CONCLUSIONS

The information identified in each of the previous sections has been integrated into GHGenius and that integration is described in the following sections along with a discussion of the results from the new model.

### 8.1 DATA INTEGRATION INTO GHGENIUS

The emissions from natural gas production in Canada are calculated on a relative basis to the US gas production energy requirements. There are separate relative performance factors for energy requirements for gas recovery, NGL production and pipeline energy. For the calculations of venting and flaring emissions, these are also calculated on a relative basis to the US emissions and there are separate factors for gas recovery, processing, and transmission and storage emissions. There are separate emission factors for downstream gas losses for the system but these will be independent of the type of gas that goes into the system.

To integrate these additional sources of gas into GHGenius the single value for each of the six relative emission factors needs to be replaced by the weighted average value for the five types of gas identified in this work. The weighting factor is a function of the year and changes as the gas supply changes. The relative factors for each of the energy factors are summarized in the following table.

**Table 8-1 New Relative Factors – Gas Energy Consumption**

|                          | Recovery | Processing | Pipeline |
|--------------------------|----------|------------|----------|
| Destination cell Sheet R | B39      | C39        | D39      |
| Solution gas             | 1.00     | 1.00       | 1.00     |
| Conventional             | 1.00     | 1.00       | 1.00     |
| Coal bed methane         | 1.00     | 1.00       | 1.00     |
| Shale                    | 1.43     | 0.00       | 1.00     |
| Tight Gas                | 1.00     | 1.00       | 1.00     |
| Frontier                 | 1.00     | 1.00       | 2.60     |
| East Coast               | 1.00     | 1.00       | 1.00     |

A similar set of values for the gas losses is summarized in the following table.

**Table 8-2 New Relative Factors – Gas Losses**

|                          | Recovery | Processing | Transmission and Storage |
|--------------------------|----------|------------|--------------------------|
| Destination cell Sheet R | E39      | F39        | G39                      |
| Solution gas             | 1.00     | 1.00       | 1.00                     |
| Conventional             | 1.00     | 1.00       | 1.00                     |
| Coal bed methane         | 1.00     | 1.00       | 1.00                     |
| Shale                    | 0.75     | 0.00       | 1.00                     |
| Tight Gas                | 1.00     | 1.00       | 1.00                     |
| Frontier                 | 1.00     | 1.00       | 1.00                     |
| East Coast               | 1.00     | 1.00       | 1.00                     |

The other difference in the gas sources is the carbon dioxide content. In GHGenius, this is dealt with on sheet F. A similar approach is used with a gas supply weighted factor calculated for the specific year that is being modelled.

**Table 8-3 New Relative Factors – CO<sub>2</sub> Content**

|                          | CO <sub>2</sub> Content<br>Sheet F A44 |
|--------------------------|--|
| Destination cell Sheet F |  |
| Solution gas             | 1.29                                   |
| Conventional             | 1.29                                   |
| Coal bed methane         | 0.00                                   |
| Shale                    | 1.29                                   |
| Tight Gas                | 3.87                                   |
| Frontier                 | 0.00                                   |
| East Coast               | 1.29                                   |

## 8.2 RESULTS

GHGenius has been expanded so that it can model different types of natural gas production. All of the existing functionality of the model was maintained. The proportion of each type of gas to the national gas pool is based on National Energy Board data and forecasts through to the year 2020. The GHG emissions results for the upstream portion of the lifecycle for each type of gas are shown in the following table.

**Table 8-4 Natural Gas Emissions by Type of Gas**

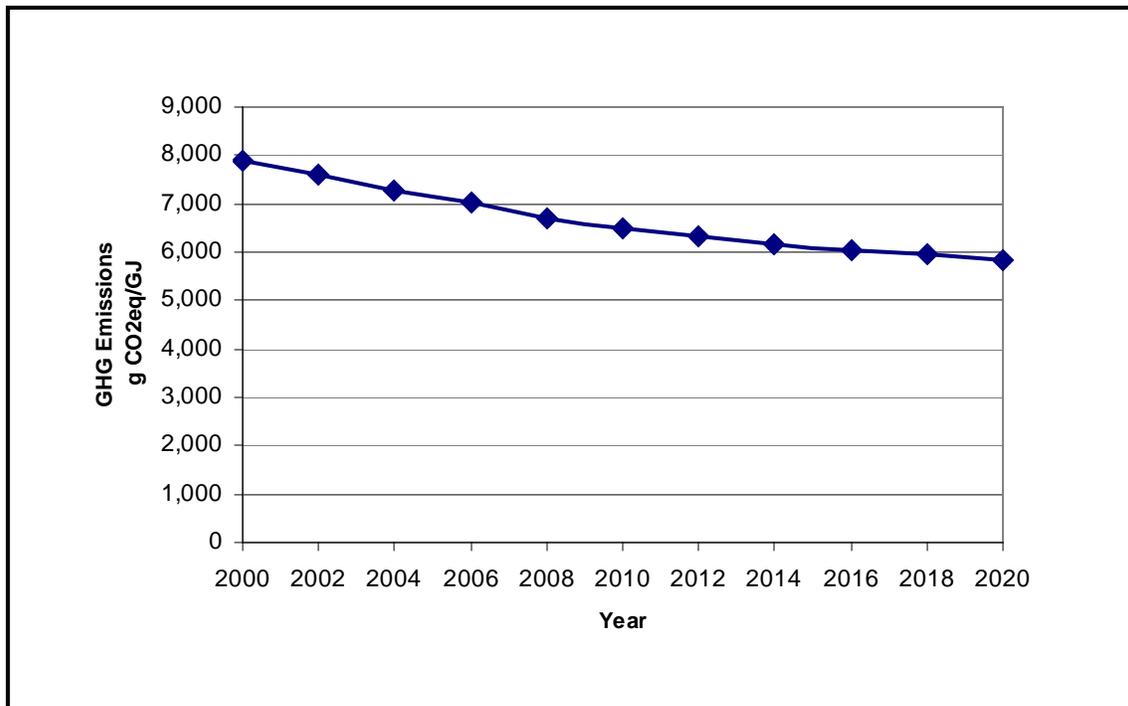
| Fuel   | Conventional Gas        | Coalbed Methane | Shale Gas | Tight Gas | Frontier Gas |
|--|-------------------------|-----------------|-----------|-----------|--------------|
| Use  | commerce                |                 |           |           |              |
|  | g CO <sub>2</sub> eq/GJ |                 |           |           |              |
| Fuel dispensing                                    | 0                       | 0               | 0         | 0         | 0            |
| Fuel distribution and storage                      | 1,303                   | 1,249           | 1,340     | 1,303     | 3,465        |
| Fuel production                                    | 1,377                   | 0               | 1,414     | 1,377     | 1,360        |
| Feedstock transmission                             | 0                       | 0               | 0         | 0         | 0            |
| Feedstock recovery                                 | 1,710                   | 1,663           | 1,742     | 1,710     | 1,697        |
| Land-use changes, cultivation                      | 0                       | 0               | 0         | 0         | 0            |
| Fertilizer manufacture                             | 0                       | 0               | 0         | 0         | 0            |
| Gas leaks and flares                               | 1,369                   | 1,029           | 1,369     | 1,369     | 1,373        |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 824                     | 0               | 2,473     | 824       | 0            |
| Emissions displaced                                | 0                       | 0               | 0         | 0         | 0            |
| Total  | 6,584                   | 3,941           | 8,338     | 6,584     | 7,895        |

The emissions from the combustion of natural gas are about 50,000 g CO<sub>2</sub>eq/GJ, depending on the combustion efficiency. The variation in the upstream emissions between the different

types of natural gas would appear to be less than 10% of the lifecycle emissions for the production and use of the gas. However, there is significant uncertainty with respect to the energy and emissions performance of the emerging sources of gas and more work is warranted to better document the emissions of the new energy sources.

The emissions of the pool of natural gas over time are shown in the following figure. The emissions do trend downwards due primarily the assumptions in the model related to methane losses. As seen in the previous table some sources of natural gas have lower emissions and other sources have higher emissions and these two trends do have an offsetting impact.

**Figure 8-1 Upstream NG GHG Emissions**



In the following table the GHG emissions for natural gas in this version of GHGenius and in the previous version are compared. The impact of all of these changes to the model is quite small for 2010 but it could change in the future as the new sources of gas contribute a large portion of the gas supply pool.

**Table 8-5 Comparison with GHGenius 3.17**

| Fuel   | GHGenius 3.17           | GHGenius 3.18 |
|--|-------------------------|---------------|
| Use  | commerce                |               |
|  | g CO <sub>2</sub> eq/GJ |               |
| Fuel dispensing                                    | 0                       | 0             |
| Fuel distribution and storage                      | 1,299                   | 1,300         |
| Fuel production                                    | 1,373                   | 1,292         |
| Feedstock transmission                             | 0                       | 0             |
| Feedstock recovery                                 | 1,706                   | 1,708         |
| Land-use changes, cultivation                      | 0                       | 0             |
| Fertilizer manufacture                             | 0                       | 0             |
| Gas leaks and flares                               | 1,369                   | 1,346         |
| CO <sub>2</sub> , H <sub>2</sub> S removed from NG | 639                     | 797           |
| Emissions displaced                                | 0                       | 0             |
| Total  | 6,385                   | 6,443         |

### 8.3 DATA GAPS AND UNCERTAINTIES

For the new types of natural gas production very little information was identified that would indicate that an assessment of the GHG emissions of gas production from these new resources was undertaken prior to the development of the resource. In many cases many millions of dollars has been invested in these resources with apparently little understanding of some of the environmental impacts. There is a definite need for a better understanding of the GHG emissions of these new sources of gas.

Should additional or new information become available in the future it will be very easy to update GHGenius with this new information.

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